The Potential for Cogeneration in the Commercial Sector

Prepared for the Ontario Ministry of Energy
by
The Proctor & Redfern Group

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EXECUTIVE SUMMARY

Natural gas-fueled cogeneration offers numerous benefits for the gas consumer, gas industry, electric utility and province as a whole. Energy and cost savings for the cogeneration user coupled with utility load leveling and better utilization of the gas transmission system results in lower energy costs. A rapidly growing number of industrial and institutional energy users are looking into this technology.

Cogeneration systems generally provide the best economic return when operated at a high capacity factor and have good overall on-site utilization of thermal and electrical outputs. Applications in the commercial field are frequently overlooked or dismissed as infeasible, generally due to the more variable loads, fewer operating hours, and lack of economy of scale for small capacity units. Although these do present obstacles to economic use of cogeneration, potential economies arising from large scale production of pre-engineered packaged systems and the higher retail electricity rates paid by commercial energy users could yield acceptable returns.

In this study we have identified those commercial applications which promise the most economically attractive potential for cogeneration. These include: Large Hotels and Motels, Restaurants, Supermarkets and Recreational Facilities.

It was discovered that, at present, the utility and cogeneration package costs do not make commercial cogeneration a feasible alternative for Ontario. However, it is felt that trends in the technology which are bringing down installed costs will make cogeneration an important option within the next 10 years.

Any programs or demonstration projects funded by the Ministry during that time to promote the technology would certainly enhance the likelihood of success.

COGENERATION IN THE COMMERCIAL SECTOR

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1.0 INTRODUCTION

1.1 Background

The commercial sector is the third largest user of electricity in Ontario. In 1985, this sector used 23 billion kWh of electricity or 21% of the total electricity used. Continued growth and increased use of electricity will push these figures to approximately 35 billion kWh or 22% of the total electricity used by the year 2000.

As part of its mandate, the Ministry of Energy wishes to assist the commercial sector to improve its energy efficiency. Cogeneration is one option available to commercial establishments to improve energy efficiency and benefit from energy cost savings or revenues resulting from the sale of electricity to the Province's grid.

It has been estimated that 460 MW of cogeneration capacity, economically viable on the life-cycle basis, could be developed in the commercial sector by the year 2000(1). The Ministry of Energy has a number of incentive programs to promote parallel generation, cogeneration and electricity conservation. The Commercial Buildings Energy Management Program is specifically developed to promote effective energy management in commercial buildings. One of the objectives of this program is to promote the development and implementation of cogeneration projects as a viable option.

The Ministry of Energy retained Proctor & Redfern Ltd. to conduct a market assessment of cogeneration potential in the commercial sector, to address these goals, and to identify key markets for developing cogeneration projects.

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(1) Cogeneration Potential in Ontario and Barriers to its Development, Acres International Ltd., February, 1987.

1.2 Objectives

The Ministry of Energy intends to use the findings of this study for two purposes:

.1 The build on the existing cogeneration information base and characterize typical cogeneration projects in different commercial subsectors.

.2 To identify, assess the impact, and rank the most attractive cogeneration opportunities in various commercial establishments where cogeneration would be a viable option, given current market conditions and emerging technologies.

1.3 Report Organization

This report is organized as follows:

Section 2 - summarizes the various tasks performed and our approach in carrying out the study.

Section 3 - identifies the types of buildings considered in this study and their energy requirements. Preferred building categories are selected for further assessment of cogeneration potential.

Section 4 - reviews current and emerging cogeneration system technologies.

Section 5 - identifies the various factors affecting cogeneration economic viability and contains the economic and sensitivity analysis of the systems.

Section 6 - summarizes building owner and operator requirements and identifies current barriers to cogeneration systems implementation.

The final two sections provide the conclusions and recommendations arrived at, as a result of the study.

Source material is listed in the Bibliography and attached Appendices contain detailed information on Packaged Cogeneration Technology and the Economic Analysis. Copies of the questionnaires used to carry out the Owner survey are also included.

2.0 APPROACH

The following approach was taken during the study to determine the market potential for cogeneration in the commercial sector:

.1 Documents recently published by various government, university and research agencies related to cogeneration potential on Ontario's commercial sector were identified and reviewed.

.2 A market survey classifying commercial buildings in terms of function (malls, office towers, hotels etc.), their energy use and sources of energy was conducted.

.3 Types or groups of buildings and establishments having potential for developing cogeneration projects were identified.

.4 Cogeneration technologies suitable for the various groups of buildings and facilities identified above were recommended.

.5 The economic viability of the recommended technologies for each group was assessed, in the form of representative case studies, given current economic conditions and using the Ministry's energy price forecasts.

.6 A sensitivity analysis on the economics of cogeneration due to changes in a number of factors including; capital costs, capital cost allowance, financing costs, availability of Class 34, electricity rates, fuel costs, and capital grants, was performed.

.7 A questionnaire was prepared and owners and operators of representative buildings in each group were interviewed to assess their willingness to:

- consider cogeneration as an option for optimizing energy efficiency;

- determine barriers to implementation and recommend how to overcome them.

.8 Key markets for developing cogeneration projects were ranked in order of economic viability.

.9 The potential impact of emerging technologies was discussed.

.10 A final report containing the information acquired, the results of the economic analyses for case studies and pertinent technical information and references was prepared.

3.0 COMMERCIAL BUILDING APPLICATIONS

3.1 Scope and Definitions

For the purposes of this study, the commercial sector is defined as consisting of the following subsectors:

	Major Category	Disaggregate Category
i.	Offices:	Private Sector Government Sector
ii.	Retail:	Food Stores General Merchandise Stores Service Stores
iii.	Hotels and Motels:	Hotels and motels with 160 rooms or more (i.e. Large Hotels) Hotels and motels with 159 rooms or less (i.e. Small Hotels)
iv.	Recreational Facilities	Health Clubs, indoor racquet courts, pools, etc.

3.2 Building Classification

3.2.1 Offices: Private and Government

The office sector is divided into private sector and government (federal, provincial and local) offices. The definition of offices used in this study excludes those buildings located on non-commercial sites even if typical office functions (e.g., clerical or managerial work) are performed in them.

The definition used in this study is from the City of Toronto Planning Board's 1974 report, Demand for Office Space in the Core Area (their definitions and estimates of office employment, in turn, are derived from the 1971 Census of CMA Toronto). The City of Toronto Planning Board estimated that approximately 28 percent of all office-oriented employment takes place on manufacturing and industrial sites in CMA Toronto. (City of Toronto Planning Board, 1975). Thus, energy consumption statistics are included for buildings in which about 72 percent of all office employees work.

3.2.2 Retail: Food, General Merchandise and Service Stores

The retail sector includes a diverse range of activities, (e.g., bakeries, barbershops; restaurants; food, department and jewelry stores) which take place in enclosed buildings. Because of the availability of good energy consumption data on food stores, for the purpose of this study, the retail sector is divided into the two broad categories of retail food stores and non-food retail stores.

Food stores are defined according to the Standard Industrial Classification Code (Statistics Canada 12-501) and include supermarkets (the major type of food store), bakeries, milk and convenience stores, fruit and vegetable stores, etc.. It should be noted that this definition includes stores which, although selling primarily food items for retail distribution, also sell a small percentage of non-food items).

The non-food sector has been further divided into two components - the general merchandise and service store sectors.

General merchandise stores are defined according to the Standard Industrial Classification System and includes all stores which primarily sell non-food commodities, e.g., department and variety stores.

The service sector includes those establishments which sell services rather than commodities. For this study, service "store" outlets were selected from the listings and definitions provided by the 1971 census of Merchandising and Services (Statistics Canada 97-742). Only those which could be appropriately classified as "retail" were selected (e.g., movie theatres and restaurants, beauty shops). Service "store" outlets such as golf clubs, ski chalets and drive-in theatres were excluded, primarily because the highly seasonal use of buildings and energy consumption patterns with which these activities are associated do not resemble other retail establishments. Service businesses which primarily take place in office buildings were also excluded since they would be included in the estimate of private sector offices.

3.2.3 Hotels and Motels

Hotels and motels constitute the dominant element in the accommodations sector of the economy. Hotels and motels are defined to include all buildings containing several rooms that are rented on a temporary basis. Unlike some types of commercial accommodation, hotels and motels operate throughout the year.

Due to the nature of available stock and energy data, hotels are not easily distinguishable from motels, therefore, both have been combined and the data has been organized to differentiate hotels and motels on the basis of size.

The category "large hotels" refers to hotels and motels with over 80 rooms while "small hotels" refers to hotels and motels with 79 rooms and under. (Virtually all motels are under 80 rooms).

3.2.4 Recreational Facilities

Recreational facilities include arenas, gymnasia, pools, indoor racquet courts and other such facilities not included in other sub-sectors. Though energy consumption statistics were not specifically published for recreational facilities, approximation's were made based on data from The Ministry of Energy's recent report, Commercial/Institutional Buildings Electrical Energy Technology Study.

3.3 Building Inventory

Table 3.1 presents the estimated total floor area, number of buildings and average floor area for each commercial subsector in the Province of Ontario.

TABLE 3.1

Estimated Number of Buildings and Total Floor Area for each Subsector

Subsector	Number of Buildings	Total Floor Area (000's sq.ft.)	Average Floor Area (sq.ft.)
Office Buildings	16,000	404,629.0	25,000
Food Stores	9,200	49,795.5	5,400
General Merchandise	19,860	192,620.0	9,700
Hotels & Motels	2,900	49,726.0	18,000
Service Stores	11,330	61,173.3	5,400
Recreation	3,870	46,404.7	12,000

Source: "Commercial/Institutional Buildings Electrical Energy Technology Study". Prepared for the Ontario Ministry of Energy by Engineering Interface Ltd. and Marbek Resource Consultants Ltd., February, 1988.

3.4 Energy Use Data

An estimate of the energy consumption in 1985 in the Ontario Commercial sector is given in Table 3-2. The table shows both electrical and total fuel consumption figures used in this study. The estimates shown in Table 3-2 were developed from reports prepared for the Ministry of Energy in 1986 (2) and a 1979 report for Energy Mines and Resources Canada (3).

Energy coefficients (kWh per square foot per year) were calculated by dividing the above energy consumption figures by the total floor area data presented in Table 3-1. These coefficients are shown in Table 3-3.

(2) "Calibration of the Ministry of Energy Commercial Energy Demand Model". Prepared by Marbek Resource Consultants Ltd., August, 1986.

(3) Patterns and Levels of Commercial and Industrial Energy Consumption: A Case Study of Metropolitan Toronto, Energy, Mines and Resources Canada, Building Series Publication #1, 1979.

TABLE 3-2
ESTIMATED FUEL USE IN ONTARIO'S COMMERCIAL SECTOR (1985)

Subsector	Electricity (MWh)	Total (MWh)	Percent
Office	9,803,606	15,918,000	39.8
Food Stores	3,561,919	4,551,000	11.3
General Merchandise	5,688,376	8,761,000	21.8
Hotels	1,195,131	2,298,000	5.7
Service Stores	2,018,201	5,554,000	13.8
Recreation	1,036,376	3,068,000	7.6
Total	**23,303,000**	**40,147,000**	**100**

TABLE 3-3
ANNUAL ENERGY USE COEFFICIENTS (EUC) BY SUB-SECTOR IN ONTARIO'S COMMERCIAL SECTOR

Subsector	Area (10^6sq.ft.)	Total Energy Use (10^6 KWH)	(EUC) (KWH/sq.ft)
Private Office	323.6	12,944	40.0
Government Office	81.0	2,974	36.7
Total Office	404.6	15,918	39.3
General Merchandise	192.6	8,761	45.5
Food Stores	49.8	4,551	91.4
Service Stores	61.1	5,554	90.6
Total Retail	303.5	18,866	62.2
Large Hotels & Motels	34.8	1,914	55.0
Small Hotels & Motels	14.9	381	25.6
Total Hotels & Motels	49.7	2,295	46.2
Recreational	46.4	3,068	66.1

3.5 Selection of Preferred Building Categories

The previous section shows that with the exception of small hotels and motels, the various subsectors all have either a high energy coefficient or represent a large percentage of the province's commercial energy consumption. Thus making each one a candidate for potential energy savings. It was necessary to further investigate each of the subsectors (with the exception of small hotels and motels) for suitability with respect to opportunities for cogeneration applications.

Not all of these buildings will be favored candidates for gas-fired cogeneration, however, because of various factors which we used as selection criteria:

.1 Building utilization is intermittent, leading to sporadic thermal and electric loads which, in turn, leads to poor utilization of cogeneration equipment with resultant poor economics.

.2 Gas fuel is not available (economically).

.3 Buildings are too few in number to be significant; cogeneration packages designed for more prevalent buildings may still be adaptable.

.4 Buildings must have both thermal and electric load in reasonable proportions. We excluded the situations where almost all electricity would be sold to the grid.

These factors were used as a broadly based screening criteria to allow us to select preferred categories of buildings. In this way, we attempted to focus on those applications which probably will define the best and most representative opportunity for future cogeneration packages produced in large quantities.

We applied the following procedure for selecting preferred building categories. First building categories were tentatively divided into two classes:

- First Priority (numerous buildings in the category, and building loads consistent with cogeneration);
- Secondary Priority (Buildings in the category are too scarce, or loads disproportioned for cogeneration).

The second step was to gather additional data on the "first priority" building categories, in an attempt to clarify what sizes of buildings within each category would be most suitable for cogeneration.

The criteria we used in the selection process are explained below:

a) Size of Building Thermal Loads: Base average thermal load for 5,000 hours per year. This could consist of hot water, space heating, or commercial use of heat such as in a laundry.

b) T/E Load Ratio: Given the building thermal load, we asked if the base average electric load was sufficient to absorb the electric output (kW) resulting from a cogeneration module operating at rated load for a reasonable fraction of the time.

c) Hours of Operation: Occupancy greater than 50% of annual hours (system operation considered essential for favorable payback period of initial system cost).

d) Building Population: Number of buildings greater than 2,000 (sufficient to support an annual cogeneration in volume of about 100 units, assuming 50% penetration and assuming sales occurring over a ten year period).

e) Fuel Availability: Pipeline natural gas available (we recognized that LPG and CNG could serve additional buildings).

As a result of this screening process, four out of eight building categories were assigned second priority; these are listed in Table 3-4.

TABLE 3-4
APPLICATIONS ASSIGNED SECOND PRIORITY FOR COGENERATION

Sub-Sector	Reason
Private Office	Poor T/E ratio
Government Office	Poor T/E ratio
General Merchandise	Low Thermal & Electric Loads
Small Hotels & Motels	Low Thermal & Electric Loads

The preferred applications are given in Table 3-5 and include four building categories. In the following sections, we will examine which types of buildings within each category appear most suitable.

3.5.1 Large Hotels & Motels: The energy characteristics resemble apartment buildings, particularly with respect to hot water usage, although the floor space (and space heating load) per occupant is somewhat lower (520 sq.ft.).

The size distribution of hotels and motels is given in Figure 3.6. About 75% of the total area is in hotels and motels having more than 25,000 sq.ft. (40 rooms). Typical electric loads range from 1.5 kW/room in the summer to 0.2 kW/room in the fall or spring. Year round, the average load is 0.6 kW/room. With a restaurant, the electric loads increase by about 0.5 kW/room year round.

Though total electric requirements of up to 2 MW are common for some of the larger hotels, we will concern ourselves with only those facilities where the commonly available cogeneration packages (up to 100 kW) could be utilized.

TABLE 3-5
FIRST PRIORITY APPLICATIONS FOR COGENERATION

Sub-Sector(building type)	Building Inventory	Size Range of Interest
Large Hotels & Motels	725	20-100 kW
Service Stores (Eating Places)	11,330	10-30 kW
Food Stores (Super markets)	9,200	20-100 kW
Recreation (hot water users)	3,870	10-30 kW

3.5.2 Eating Places: About half of these establishments use natural gas for heating or hot water; this would be essential for gas-fired cogeneration. Some other important factors which will affect the use of cogeneration in restaurants are as follows:

- Restaurant and bar owners typically would not make the cogeneration decision, because almost all use rented space. Moreover, energy costs represent only 2-4% of a typical restaurant operating budget; therefore cogeneration could not have a sizable impact.

- Many restaurants and bars are not individual buildings, but rather are attached to shopping malls or other commercial buildings. This means that the matching of cogeneration energy outputs can take into account the entire building HVAC system.

- Most restaurants have electric loads far in excess of 30 kW, because of refrigeration, lighting, air-conditioning, and electric cooking equipment. Because the thermal loads are more modest than this, it can be assumed that 10-30 kW cogeneration systems would be sized primarily for thermal loads.

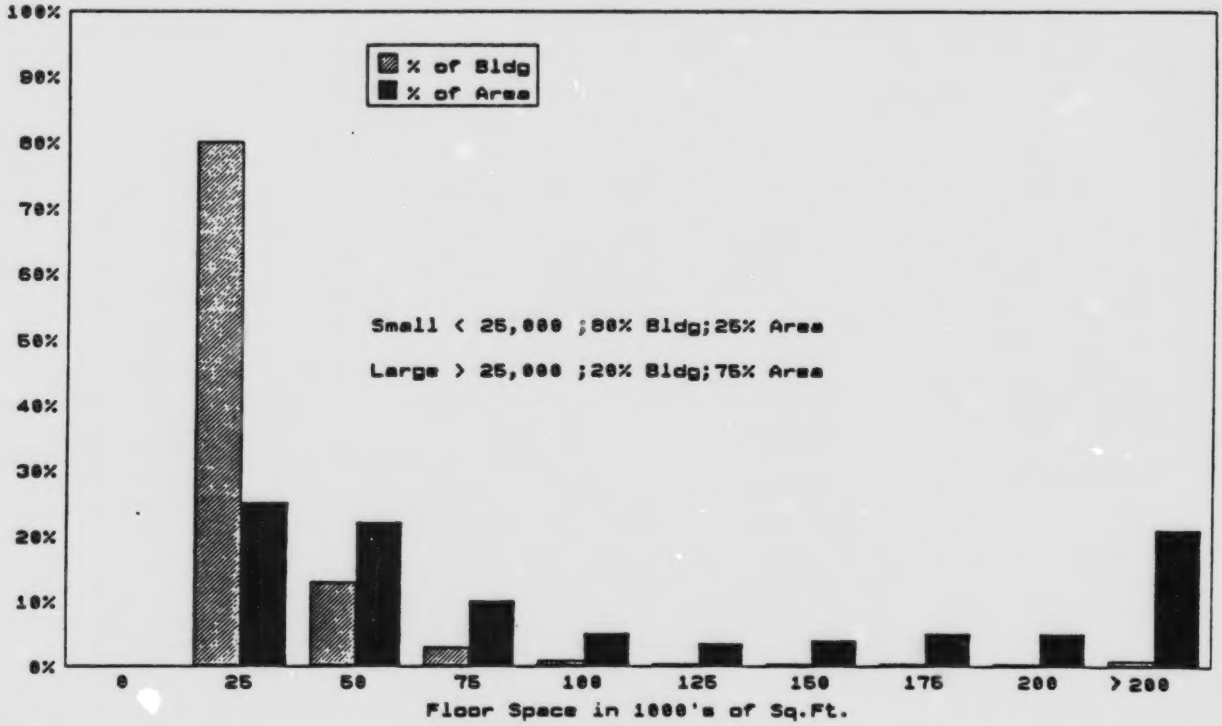
- Small fast food restaurants are lower priority than other eating places because of their relatively low thermal loads (due to the use of such items as microwave cooking and disposable plates).

3.5.3 Supermarkets: Although supermarkets are fairly small gas users, they do have the large, continuous energy demands necessary for cogeneration to provide economic benefits. Moreover, supermarket managers are highly motivated to save energy since it represents one of their largest controllable operating expenses. In a typical supermarket, the refrigeration system accounts for 54 percent of the energy consumption costs. A cogeneration package, tailored to provide the shaft power required for supermarket refrigeration, would provide an attractive opportunity to reduce energy costs.

3.5.4 Hot Water Users: The final group of commercial buildings are those which utilize large quantities of hot water to serve their commercial function. Recreation Clubs with pools or hot shower facilities are an excellent example.

(Laundries, including dry cleaners and garment service establishments which use natural gas for hot water should also be included. The electric load for a typical laundry with 25 washers and 15 dryers is 16 kW, making the small cogeneration packages, described in the next section, an ideal fit.)

FIGURE 3.6 HOTEL/MOTEL TOTAL ONTARIO FLOOR AREA (12)



4.0 COGENERATION SYSTEM TECHNOLOGIES

From the Building Energy Use Profiles defined in the previous section, it is clear that cogeneration systems of 30 to 100 kW would be the most suitable. In this load range, reciprocating internal combustion engines are the most common prime mover. Several Manufacturers have developed packaged gas fired units in this range. For the rest of this report we will concentrate on these packaged, gas fired, units.

4.1 Present Cogeneration Technologies

Six packaged cogeneration systems available in North America and Europe are listed in Table 4.1. As indicated in the Table, the most practical unit in reasonably widespread use (over 80 installed) is the 60 kW TECOGEN system. However, Waukasha has recently introduced systems of 30 to 375 kW capacities which are in the range of interest, as well as a new 200 kW packaged system offered by TECOGEN.

There has been considerably more activity in small scale cogeneration in Europe. For example, over 500 Fiat Totem units (15 kW) are installed in Europe - primarily via gas industry sponsored programs. These systems utilize a modular design philosophy which is directly applicable to the study at hand.

In addition, there is experience in Europe (primarily Germany) with engine driven heat pumps which deal with many of the same prime mover packaging, reliability, and institutional issues as cogeneration units. VW has installed over 40 engine-driven 25 kW heat pump modules, which can be considered a specific form of cogeneration modules.

TABLE 4 -1
PACKAGED COGENERATION SYSTEMS

Manufacturer Model	Fiat Totem	Holec Nutec-18	Teledyne Total Power	Tecogen CM-60*	M.A.N. E-2566	Cogenic M100**
Output - Electric	15 kW	18 kW	22 kW	60 kW	90 kW	100 kW
Output - Thermal	38.7 kW	42 kW	55 kW	129 kW	140 kW	185 kW
Number installed (9/85)	500+	180-200	NA	350	420	NA
Engine	Fiat	Ford	TM Industrial	GM Marine	M.A.N.	NA
Installed Price ($US)	$22,000	$26,000	NA	$78,000	$88,000	NA
Maintenance	1200 hr	500-700 hr	$0.40/hr	$1.00/hr	NA	NA
Electrical Efficiency***	23%	25%	24%	26.4%	27.4%	28%
Overall Efficiency***	83%	75%	85%	83.2%	73.4%	81%
T/E Ratio	2.5	2.3	2.5	2.15	1.6	1.85
Package Size	3.8x3.4x3.5 ft.	NA	6.5x2.3x3.4 ft.	6x3x3 ft.	8.6x3.8x6.6 ft.	3x7x7 ft.
Package Weight	NA	NA	2,000 lb.	2,600 lb.	5,100 lb.	5,300 lb.

* Also available in units of 30, 75, and 200 kW
** Also available in units up to 1.125 MW.
*** Based on fuel higher heating value.

The experience with these cogeneration units provides useful performance, cost, and operational information with which to make initial judgments on the prospects for the cogeneration systems of this study. As well it will allow us to identify and quantify problem areas requiring resolution. In particular, this experience provides insights on the potential for conventional reciprocating I.C. engine technology in small units.

The following section briefly describes the technical and economic performance of currently available equipment, the trends in these parameters, and the areas, particularly interconnect methods, where current technology would probably not be suitable if down scaled into the range of primary interest in this study.

4.2 Existing Packaged Units

Most currently available sub-100 kW cogeneration units are assembled utilizing commercially available engines, heat exchangers, generators, and control components.

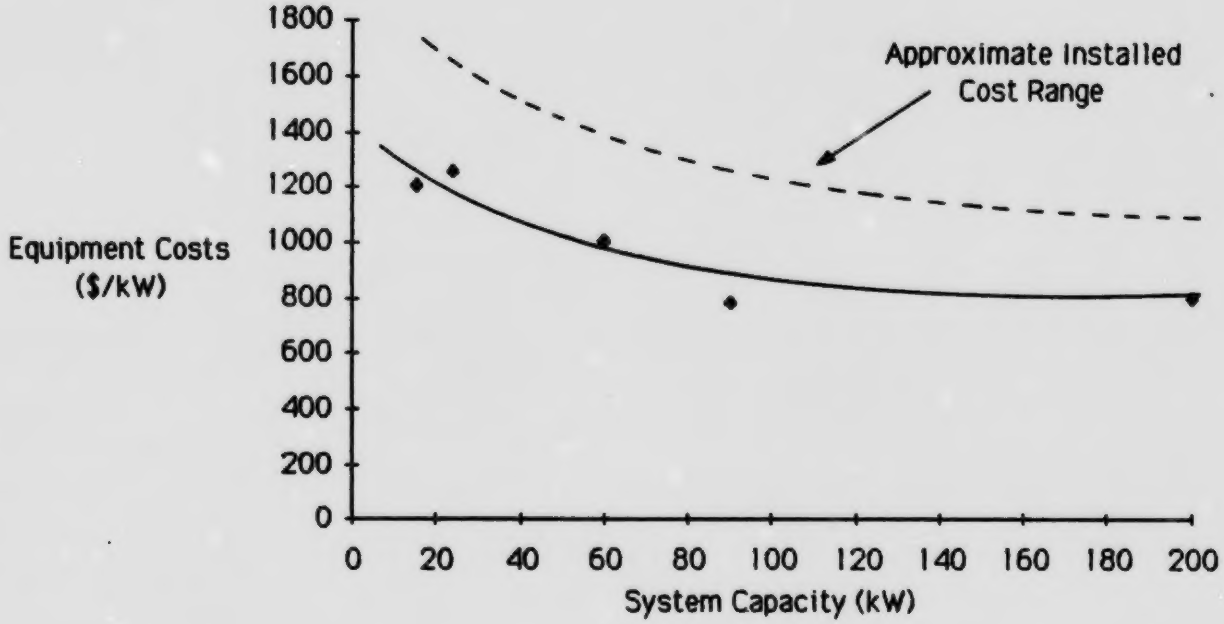
The subassemblies are selected so that they fit into compact modular packages with ease of maintenance and installation being a primary consideration.

All of these units utilize production reciprocating I.C. engines from large market applications, adapted for cogeneration duty. For example, the TECOGEN system uses a modified GM marine engine which is, in turn, based on an automative engine block. The FIAT Totem uses a Fiat engine, while the HOLEC systems use Ford automotive engines with few modifications.

4.2.1 Initial Cost

Figure 4.2 shows the initial cost of the currently available equipment. As indicated, for larger systems (60-100 kW) the equipment package costs are in the $600 - $800/kW range for the U.S. based systems. The equipment costs

EXHIBIT 4.2 - COST TRENDS FOR AVAILABLE COGENERATION PACKAGES



for smaller (< 20 kW) units is somewhat higher at about $900/kW. Installed costs are quite variable depending on site specific application, location, and local capabilities of the distribution organization. Typically, installation adds 30-50% to the package costs.

The prime movers used by different manufacturers have distinctly different cost/durability characteristics. For example, Waukasha uses a robustly designed industrial quality engine while Thermo-Electron uses an automotive derivative engine which is referred to by some as "expendable" since it is assumed that it will be replaced rather than rebuilt periodically.

Even with the above caveats, the information of Figure 4.2 displays several trends:

(a) There is a general tendency for systems to become more costly as size decreases. This results from economics of scale associated with almost all system components - most notably the engine, electric utility interface equipment, and controls.

(b) The installed costs of systems in the upper end of the range of interest approach levels of $1000 - $1500/kw which could be of practical interest. This observation is, however, dependent on achieving acceptably low O & M characteristics and other economic considerations as discussed below.

4.2.2 Efficiency

The cogeneration units utilize reasonably efficient engine systems with design load electric efficiencies ranging between 23% for the TOTEM unit to 28% for the COGENIC unit. We base efficiency figures in this report on the higher heating value of the fuel because current heat exchanger technology permits flue gas condensation.

Overall combined efficiencies for the systems range from 75% to over 85%. The higher end of this efficiency range implies that condensation is taking place in exhaust gas heat recovery units.

4.2.3 Unit Size

As shown in Table 4.1, the cogeneration systems are provided in packages which will fit in most commercial mechanical rooms. The packages are typically mounted on skids which contain all the required equipment and need only be connected to the building services.

4.2.4 Noise

Manufacturers have endeavored to limit noise levels to acceptable limits by using mufflers on the engine exhaust and careful packaging with sound insulation. The noise levels of current equipment are about 50-60 dB, probably low enough for most commercial applications where equipment would be placed in a special utility room containing other equipment with similar noise levels.

4.2.5 Emissions

Little information is available on the emission characteristics of small cogeneration units since few regulations are applicable to this equipment. Manufacturers currently take no special steps to reduce emissions over those which occur from the engines, and therefore, it is probably reasonable to assume the engines have NO_x levels which may be unacceptable in the future if regulations governing emissions from small generators are implemented. Moreover, the Lean-Burn NO_x control techniques being developed for 100-1000 kW cogeneration engines may not be applicable to small engines which cannot be readily turbocharged.

4.2.6 Maintenance Requirements

Figure 4-3 indicates the cost of maintenance based on often limited information available on this critical subject. Information on the TECOGEN, WAUKASHA, and larger compressor systems is based on maintenance contract terms that manufacturers are willing to offer. Other information is based on estimates from manufacturers but does not necessarily reflect contractual terms into which they would enter.

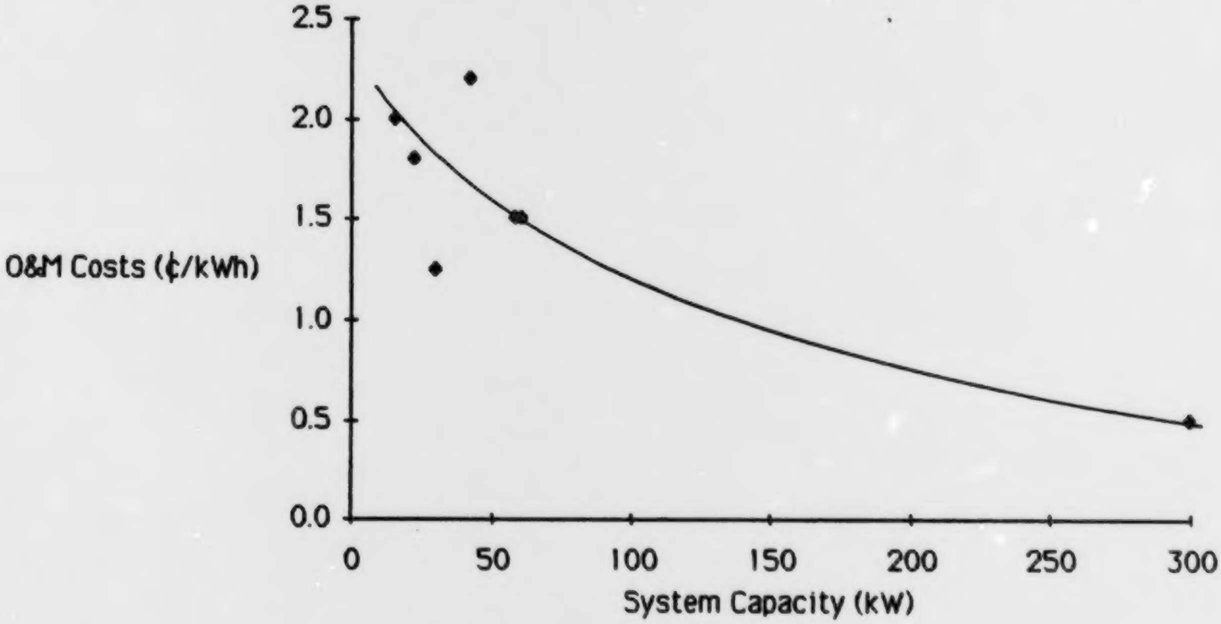
The costs shown indicate:

(a) The O & M costs show a definite trend to increase as unit size decreases. For example, larger (60 kW) units have O & M costs of about roughly 1.5 cents/kWh ($1.00 per operating hour) while units at the lower end of current practice (15 kW) have O & M costs in excess of 2 cents/kWh. This trend toward higher O & M costs reflect the fact that for smaller units much of the cost of maintenance is associated with travel to the site, oil changes, and other routine maintenance functions which are not very sensitive to system size.

(b) The O & M costs tend to be related directly to hours of operation. The costs normalized to cent/kWh assume the system operate at as near rated capacity at all times. Operational strategies resulting in extensive part load operation would incur higher O & M cost on a cent/kWh basis.

The increase in normalized O & M costs with decreasing size is probably the single most critical issue relative to small scale cogeneration.

EXHIBIT 4.3 - O&M COST TRENDS FOR CURRENTLY AVAILABLE COGENERATION PACKAGES



4.2.7 Interconnect

Interconnection equipment must serve to: meter utility supplied power; meter power sold to the utility; assure proper phasing of utility and cogenerated power; and allow utilities to disconnect cogeneration systems for safety reasons. Equipment requirements to meet these needs however, are not well defined for small-scale systems. If measures could be taken to reduce interconnection requirements, additional savings could be obtained to offset the somewhat low buyback rates and improve the overall economics for utility interconnections.

Cogenerators require switchgear, metering, controls and protective devices in order to be interconnected with a utility. The operation of generators and alternators impact the type of equipment required by a small power producer.

Auxiliary equipment required for large cogeneration units operating in parallel to a utility network have been well established although variations of considerable breadth are encountered. The problems of controlling and protecting smaller machines are not greatly different. As the value of a small machine in much less, expensive equipment to specifically protect the machine itself, however, is not cost-effective. Additionally, as a malfunction of a small machine has substantially less adverse impact on a much larger system, the system protection need not be as precise and sophisticated, but it must be there.

A number of electric utilities in the U.S. have explored the requirements for cogeneration safety and control and have published their requirements. A composite of those published by Boston Edison and Southern California Edison are presented below: (Ontario requirements are similar).

1. Switchgear:

   - Manual disconnect switch accessible from outside or meter;
   - Electrically operated contactor or circuit breaker for connecting the alternator when synchronized*; and
   - Overcurrent protection.

2. Metering:

   - Kilowatt hour meter(s) to measure energy input only, input and output separately, or net energy flow depending upon the operating agreement;
   - Kilovar hours in +; and
   - Kilowatts in and out+.

3. Controls:

   - Synchronizer or sync check device;*
   - Voltage regulator+;
   - Variable capacity control+; and
   - Engine governor.

4. Protective Devices:

   - Overcurrent protection;
   - Over and Undervoltage relays;
   - Over and under frequency relays;
   - Reclose lockout*; and
   - Dead line check*.

* Not required for induction generators
+ Required for larger (>200 kW) machines

The prices for the various switching, control and protective devices can vary widely depending upon precision, reliability, and sophistication required. The devices made today have been principally designed and built to serve larger alternators in relatively small quantities. Based upon presently available equipment, the following represents a rough estimate of devices and costs for a 30 kW synchronous alternator.

Device	Price	Quantity	Extension
Disconnect	$ 200	1	200
Contactor	250	1	250
kWh Meters	100	2	200
Synchronizer	700	1	700
Governor	650	1	650
Voltage Relays	500	2	1,000
Frequency Relays	1100	2	2,200
		Total Cost	$5,200

These costs are for actual devices only and do not include items such as mounting boxes, installation, and testing. As an induction generator will not need a synchronizer and can use a less precise governor, its devices will cost about $1,000 less.

High interconnection costs make smaller scale cogeneration systems less economical due to economies of scale. Efforts should be made to define and work with utilities to modify requirements and design equipment. An emphasis should be given toward small-scale applications. In this way, changes may be able to be incorporated by utilities that would relieve some interconnection requirements and costs for smaller power systems which are unnecessary and penalize smaller cogeneration systems.

4.3 Alternative Engine Technologies*

Table 4-4 provides an overview of alternative engines which are being considered for use in small scale cogeneration systems along with their primary potential advantages. These range from highly development small scale Brayton cycle engines based on ceramic turbo charger technology to rotary I.C. engines which represent relatively modest deviations from commercially available technology. Each of these engine options is discussed briefly in the following sections.

4.3.1 Rotary I.C. Engines

As indicated in Table 4-5, about four companies are currently manufacturing and/or developing rotary I.C. engines. The impetus behind the largest program (MAZDA) has been for high performance automotive engines. However, smaller engines in the power range of interest have been built in the past and are currently under development by WEDTECH and Teledyne. Rotary engines are currently available in automobiles and have shown significant improvements in reliability and performance over the past few years as the technology improves.

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* The majority of this section was published in the September 1986 report on System and Technology Concept Evaluation for Small Commercial/Residential Cogeneration Applications, and is included to display the significant amount of work currently being performed in the development of economical small scale cogeneration systems.

TABLE 4.4 - ALTERNATIVE PRIME MOVER OPTIONS (29)

	Potential	Development Issues	Time To Commercial Availability* (years)
Rotary I.C. Engine	Compact size, low weight	Long life	2-4
Organic Rankine Cycle	Long life, low noise, low emissions	Large size Low efficiency	3-6
Stirling Engines			
o Free Piston	Low noise & emissions	Long Life	3-6
o Kinematic	High efficiency	Reliability	3-6
Brayton Cycle	Low cost and maintenance	Low efficiency (1) High Speeds (2)	5-10
Fuel Cells	High efficiency, Low noise & emissions	High Cost	5-10

* With a focused development program
(1) Experience to date in small sizes
(2) Complicates generator and electronics

TABLE 4.5 - MANUFACTURERS AND DEVELOPERS OF ROTARY IC ENGINES (29)

COMPANY	CAPACITY (Hp)	TYPICAL APPLICATIONS	STATUS
Mazda		Automotive	Commercially Available
John Deere & Co.	200-400	Military Generators and aircraft propulsion	Developmental
Wedtech	<10	Heat Pump	Developmental
Teledyne	12-15*	Commercial Heat Pump Drives	Developmental

* Based on a derated 45 HP engine - speed reduced from 7200 RPM to 3500 RPM.

Advantages of Rotary I.C. Engines

- **Size & Weight:**

The configuration of the rotary engine eliminates the equivalent of a crankcase which is a major portion of reciprocating engine size and weight. Additionally, the steady motion of the trochoid seals may allow for faster operating speeds than reciprocating engines of similar durability. Consequently, there is good potential for rotary engines to be significantly smaller and lighter weight than reciprocating I.C. engines - even after allowance are made for aerated operation to attain needed reliability. Smaller size and weight, in turn, would lead to smaller package size and enhanced modularity, thereby, facilitating installation and maintenance.

- **Maintenance and Life:**

There are several reasons to project that rotary I.C. engines have good reliability and life potential. They do not have any valves which eliminate one of the major maintenance items in many high efficiency four stroke reciprocating engines. Positive lubrication oil injection eliminates the need for oil changes. Developers of the engines report oil consumption levels comparable to lower than reciprocating engines so that oil reservoirs can be sized for very long intervals between replenishment. As indicated before, however, these positive factors are somewhat counter balanced by remaining uncertainties in the life and reliability of the special seals associated with this class of engine.

- Initial Cost:

The lower size and weight potential of rotary engines should lead to engine costs comparable to or lower than reciprocating engines despite the relative complexity of highly finished trochoid shapes. Moreover, the smaller engine units could lead to other system packaging cost reductions, and reduce installation costs.

Disadvantages of Rotary I.C. Engines

- Life and Reliability Uncertainties:

There has been only very limited durability testing undertaken with rotary engines-input reflecting the initial emphasis on automotive applications. However, recent testing at Teledyne for over 1000 hours indicates that earlier problems with seals are on their way to resolution. Similarly, MAZDA reports excellent reliability of their automotive engine as compared to reciprocating engines. Nevertheless, life and reliability of rotary engines given their special sealing, lubrication, and thermal environment characteristics remains a major uncertainty for use in cogeneration applications.

- Efficiency:

Early rotary engines had poorer efficiency than their reciprocating counterparts. At least in larger sizes (automotive and above) this appears to be no longer the case and, in fact, the stratified charge rotary engine being developed by John Deere may even have advantages in this regard. The latter firm has reported efficiency levels in excess of 30% when burning military fuels (CP-4, etc.) in a 400 Hp engine and feel that efficiencies approaching this level may also be possible using natural gas with proper engine modifications. However, the efficiency of smaller (< 30 kW) units burning natural gas may still be negatively impacted by the relatively high surface to volume ratio of this engine class - particularly at the lower end of the power range being considered (< 10 kW).

4.3.2 Brayton Cycle Engines (Gas Turbines)

There is only limited commercial experience with gas turbines in the power range of interest. This experience is limited primarily to Auxiliary Power Units used on airplanes and military generator set developments. Table 4-6 indicates the availability and status of gas turbines with capacities below 100 kW.

The primary incentives for utilizing gas turbines in these applications have been low weight and size and high reliability as compared to positive displacement equipment. As a result, almost all these systems are based on simple cycles (unrecuperated) and relatively low operating temperatures resulting in efficiency levels of only 4% to 10%.

Gas turbines in the capacity range of interest will have rotational speeds of 60,000 - 120,000 RPM.

Two approaches to extracting power from the high speed gas turbines are or could be utilized:

- Gearing down the high speed turbine output so that the output shaft runs at a speed consistent with conventional generators (3,6000 RPM).

- Mounting a high speed alternator on the turbine shaft which allows for "floating" the whole rotating package on gas bearings. This approach does, however, result in the generation of high frequency power which must be subsequently converted

TABLE 4.6 - GAS TURBINE OPTIONS (29)

		GENERATOR SETS				AUTOMOTIVE	
		Garrett	Tierney Turbine		Turbomach Titan	Garrett AGT101	Alliston
	Capacity - kW	30	10	30	60	74.8	75
Design Features	Cycle	Regenerated	Simple	Simple	Simple	Regenerated	Regenerated
	Materials	Metallic	Metallic	Metallic	Metallic	Ceramic	Ceramic
	Process Ratio					5:1	4.5:1
	Turbine Inlet Temp. - F		1200	1400		1600-2400	2350
	Exhaust Temp. - F		740	950			550
Rated Efficiency - %		16	4	9.5	14	30-50, also good at Part Load	39
Cost Life Maintenace	First Cost - $	30,000	17,000	21,000		1500 Target	
	Life - 1000 hours		6-10 Multifuel 50 - Natural Gas		6 MTBO	3.5 (Auto Service) (Better in Cogen Service)	
	Maintenance Intervals		Change Oil at 20-50K Hours				
	Noise		80 dba 6 ft. from Panel			Quiet with Refrigerator	
	Emissions					Will Meet Future Req't.	
Commercial Status		Army Funding Discontinued Garrett Doing Some Devel.	Being Supplied to Army	Available Catalogue Item	Available Catalogue Item	Technology Program Low Cost Auto Eng. Not Available for 10 years Maybe Higher Cost Specialty Engine Sooner	

to the desired form via power conditioning units.

The latter approach has the advantage of potentially very long life and high reliability by virtue of eliminating rubbing surfaces and the need for lubrication. However, even the systems using gear boxes have reported quite favorable maintenance characteristics. The following discussion on size, and weight assume the high speed alternator approach is utilized; however, this should not preclude consideration of gear down systems which would increase size/weight somewhat but simplify design of the electronics packages, and allow the use of conventional, low cost, generators.

Advantages of Gas Turbines

- Small Size & Weight:

The high operating speed (around 100,000 RPM) of small gas turbines results in a small rotating package. For example, typical turbine diameters would be about 3" for a 30 kW unit. Even with the addition of an effective recuperator, the overall package would be relatively compact and lightweight.

- Modularity/Ease of Maintenance:

The only moving part in the gas turbine would be rotating unit consisting of a turbine-compressor-high speed alternator subsystem. The very small size of this subsystem referred to previously has the added advantage of facilitating its replacement in the field thereby simplifying the whole maintenance procedure.

- **High Reliability:**

The rotating unit would be mounted on gas bearings thereby eliminating rubbing surfaces and leading to potential high reliability - particularly under steady state operating conditions. This high reliability potential is demonstrated by APU systems which often operate several thousand hours without any maintenance cost.

- **Low Cost Potential:**

The aforementioned mechanical simplicity (1 moving unit) of the system could lead to low engine costs - particularly if advanced in ceramic turbo-charges technologies are successful. This development would allow for adapting technologies in place for large markets to be used for critical system components.

It should be noted, however, that the high speed operation of gas turbines leads to the need for special high speed alternators and power conditioning units (to convert to 60 Hz power) which adds other potentially significant cost factors.

Disadvantages of Gas Turbines

- **Efficiency Uncertainty:**

Brayton cycle power systems are, for basic aerodynamic reasons, most easily implemented for larger systems. In the small sizes under consideration, the operating speed of rotating equipment increases, aerodynamic losses increase, and the effect of clearances on leakage increase. Additionally, the means for achieving high operating temperatures (1600^{o}F) in large systems, such as blade cooling, are not, as a practical matter, available in such small units.

These disadvantages have not been very important in the small units built to date since high efficiency has not been a very critical operating parameter. Larger recuperated gas turbines (1000 kW) have demonstrated efficiency levels in excess of 30% and as high as 35%.. However, it is not clear that small units can attain the efficiency levels (25%$^+$) required for practical small scale co-generation units given the realities of manufacturing tolerances, thermal expansion problems associated with high temperature operation, and leakage associated with both the turbo equipment and the recuperator (if a rotary recuperator, such as being developed for automotive applications, is used).

The questions of efficiency are also further complicated in those operational modes requiring frequent starting and stopping and/or part load operation which is particularly troublesome for gas turbine systems.

The development of ceramic components could provide one of the means for addressing these efficiency uncertainties due to their low thermal expansion coefficients (allowing for tighter clearances), high temperature capability, and low rotating mass.

- Cost Uncertainty:

The small size and superficial mechanical simplicity of the rotating package of a gas turbine system certainly has favorable cost implications and is one reason that interest in this option remains high. However, the cost of a gas turbine unit for this application will also be critically influenced by:

- The cost of highly effective recuperators needed to achieve acceptable efficiency levels;
- The cost of high speed alternators (or high speed gearing system);
- The cost of power conditioning units to convert high frequency A.C. A.C. to 60 Hz A.C. for those systems using high speed alternators.

Currently, there is little information available on the total cost structure of a gas turbine/generator/power conditioning system on which to make judgment.

4.3.3 Stirling Engines

There has been a major effort by the gas industry, to develop Stirling engines for heat pump, small generator, solar space power, and vehicular drive applications (Table 4-7). Many of these programs have focused in the power range of interest in this study. As a result of these programs a strong technology base has been developed which is applicable to small co-generation systems. However, none of the systems are currently commercially available and, as indicated below, several important performance and cost characteristics for co-generation applications still need to be demonstrated.

Advantages of Stirling Engines

- High Efficiency:

Ideally, Stirling engines have very high efficiency potential when working at temperature levels attainable with metallic alloys (500 - 800°C). Kinematic Stirling Engines have confirmed this efficiency potential with efficiencies as high as 35% measured on automotive test engines. Recently, Free Piston Stirling Engines (FPSE) have also verified efficiency levels approaching 30% in a heat pump application.

- Low Emissions:

Being an external combustion system, Stirling engines have the potential for low emissions - an advantage which provided the initial rationale for the automotive program. Reliably achieving this advantage will be complicated

TABLE 4.7 - FIRMS DEVELOPING STIRLING ENGINES (29)

KINEMATIC ENGINES	Capacity	Applications	Status
■ Mechanical Technologies, Inc.	100 Hp	Alternative	Advanced Development
■ Stirling Power Systems	15-30 Hp	Generators	Commercial Prototypes
■ Sunpower	< 10 Hp	Remote Power*	Commercial Prototypes
■ United Stirling		Automotive Marine Propulsion	Advanced Development
FREE PISTON ENGINES			
■ Mechanical Tech. Inc.	3-25 Hp	Heat Pumps Space Power	Advanced Development
■ Sunpower	0.5-3 Hp	Cryogenic Coolers Air Conditioners Generators Heat Pumps	Advanced Development
■ General Electric	3 Hp	Heat Pump	Program Terminated
■ Homach Systems, Ltd.	< 1 Hp	Remote Power	Commercial Prototype

* Biomass fired engines using air as the working gas.

by the relative high levels of air preheat required of efficient operation which may necessitate employing EGR (or some other method of NOx reduction) to meet possible emission regulations.

- Low Noise and Vibration:

Stirling engines have no valves and utilize a continuous combustion process. Consequently their noise and vibration levels are very low and such engines should readily meet cogeneration system requirements.

- Life & Reliability:

All Stirling engines have been the advantage of not requiring valves or subjecting the working space to hot combustion gases. These characteristics would tend to improve the life and reliability characteristics of this engine class. In addition, the Free Piston Stirling Engine eliminates the need for hermetic piston rods and a highly loaded crankcase mechanical drive with associated bearings and seals. In fact, in its simplest configuration the FPSE has only two moving parts, a displacer and a power piston. The power piston can be coupled to a linear alternator for use in cogeneration applications. The mechanical simplicity potential of the FPSE is used as the primary basis of the argument for very long life and good reliability. This argument can be further reinforced for those configurations using gas bearing and clearance seals in the engine resulting in no rubbing surfaces to contribute to wear. Such nonrubbing seals have, in fact, demonstrated good life potential when used in specialized refrigeration equipment being developed for space use and in small heat pumps.

Recently, there has been progress in verifying the life and reliability potential of Stirling engines. Kinematic Stirling engines have reportedly been operated for up to 10,000 hours with few problems while NASA has recently completed over 1000 hours of testing with a FPSE/linear alternator system, designed for 25 kW of output.

Disadvantages of Stirling Engines

- Life & Reliability Uncertainty:

The above discussion indicates the rationales for projecting long life and high reliability for Stirling engines. However, the experience to date still does not come close to the needs of co-generation units which might require in excess of 8000 operating hours per year. In both KSE and FPSE the life of the hot end assembly which operates at $1400^{O}F^{+}$ requires definition. KSE have additional questions relative to shaft and piston seals while FPSE have life questions relative to seals and bearings.

Demonstrating adequate life and reliability is probably the most pressing performance issue relative to this engine class.

- First Cost:

Preliminary cost estimates for Stirling engine heat pumps indicate that O & M prices of about $300/kW for a 3 kW unit might be attainable as production quantities approach 50,000/year. This is probably within the range of interest for use in cogeneration systems. However, Stirling engine/generators are likely to have significant cost premium over even robustly built I.C. engines due to their need for a relatively sophisticated combustion system, heater head, and air preheater subsystem. Also, their cost in more modest production quantities will be much higher than that indicated above which could complicate the early introduction of this engine class in cogeneration applications.

4.3.3 Organic Rankine Cycle (ORC) Engines

Prototype ORC engines have been developed for a variety of solar, geothermal, and waste heat recovery applications over the past 10 years. These systems are based on technologies developed for gas fired air conditioning, automotive, and small generator, applications since the late 1960's. Table 4-8 indicates a partial listing of ORC engines currently available, at least as commercial prototype.

Advantages of ORC Engines

For small scale cogeneration applications the primary advantages of ORC engines are:

- Potential High Reliability/Long Life:

The ORC engine is based on the same thermodynamic cycle as vapor compression heat pumps which is one of the most reliable thermo-mechanical systems in operation. For example, ORC engines developed by ORMAT have demonstrated many tens of thousands of hours of uninterrupted service and are used in remote locations where high reliability is of a premium. Similarly, Sundstrand has operated systems of the 200 kW level for close to a year without shutdown or servicing. More recently, Sundstrand has accumulated thousands of hours of operation on 500 kW waste heat recovery units with few reliability problems. This high reliability is due to modest operating temperatures ($< 700^{O}$F), the use of a closed cycle system, and the use of turbo equipment rotating on fluid bearing (i.e. no rubbing or wearing surfaces).

TABLE 4.8 - SUPPLIERS OF RANKINE CYCLE ENGINES (29)

SUPPLIER	WORKING FLUIDS	POWER OUTPUT (kW)
Thermo Electron Corporation	Water, Flourinol	400-15,000[1]
Sunstrand Corporation[4]	Toluene	25-600
Mechanical Technologies, Inc.	Water, R-11	500-2,500
Whiting Corporation[2]	MCB	300-600
Barber-Nichols Company	Toluene, Isobutane, R-11	15-500[3]

1. Higher end of range with water only.
2. Division of Wheelabrator-Frye, Inc.; distribute units manufactured by ORMAT of Israel.
3. Primarily used to date in solar and geothermal applications; could be adapted for heat recovery and cogeneration functions.
4. Systems originally developed with gas industry support for total energy applications. Recent work focusses on high reliability systems for remote areas and space power.

- Low Emissions:

The primary incentives for developing ORC engines for automative applications in the 1960's and early 70's were their demonstrated potential for very low emission levels. Due to its relatively low operating temperatures (< $750^{O}F$), the combustion conditions in the "boiler" of an ORC are not substantially different from in a conventional boiler. As a result, emission levels from ORC engines should not be significantly different than for conventional space/water heating systems, and low emission levels have been consistently demonstrated on developmental equipment.

- Low Noise & Vibration:

The only moving part in an ORC is the "combined rotating unit" consisting of the turbine-feedpump-generator subsystem. This unit can use fluid bearing and has no associated valves for noise and vibration levels of ORC engines should, therefore, be similar as for conventional heating equipment.

- Ease of Maintenance:

The condenser, boiler, regenerator heat exchangers are the major subsystems contributing to the size and weight of ORC engines. These are passive components and should contribute minimally to O & M needs. The only moving component is the turbine-feed pump assembly which is very compact in size and can be readily replaced in case of malfunction. Consequently, appropriately designed ORC engines can be easily field maintained.

Disadvantages of ORC Engines

The above advantages are clearly important ones for cogeneration applications and were the reason why the gas industry supported their development for air conditioning and cogeneration applications in the 1960's. However, ORC engines also have several disadvantages which would have to be addressed for use in the power range of interest:

- Low Efficiency Potential:

The electric conversion efficiency potential of ORC engines is about 22 - 25% based on currently available working fluids such as Toluene and Flourinol. This efficiency is on the lower end of that desirable. It is however, still within the range of interest, particularly in applications with large and steady thermal loads.

- High Initial Cost:

ORC engines are, in large part, an assemblage of heat exchangers which must be very effective to achieve the efficiency range indicated above. As a result there is still considerable uncertainty as to the cost reduction potential of ORC engines particularly in smaller sizes. Capital costs of about $1000/kW are typical in the 30 kW power range.

- Low Heat Rejection Temperatures:

The efficient operation of ORC engines requires operating the condenser at low temperatures - certainly less than 200^{O}F and preferably nearer 100^{O}F. This will limit the use of such systems to applications where space heating or hot water generation are the thermal loads. As a practical matter this may not be a serious drawback in the size range and applications of interest where these are major loads. It does, however, eliminate the potential in the future of using heat actuated cooling in conjunction with the heat recovery process.

5.0 ANALYSIS OF COGENERATION SYSTEMS

5.1 Factors Affecting Economic Viability

Many factors affect the economic feasibility of a cogeneration system at a particular site. These include application parameters such as heating, cooling and electrical loads and their coincidence, building occupancy schedules, and ease of integration of cogeneration into the existing building energy system; equipment parameters such as electrical and overall efficiency, ratio of thermal to electrical output, quality of recovered heat, initial cost, and maintenance expense; and utility parameters such as natural gas and electricity prices and grid interconnection requirements.

5.1.1 Installed Costs

A critical issue relative to assessing the potential of small scale cogeneration is quantifying the approximate range of first costs such systems can have and still expect a significant market penetration. The primary benefit to the consumer will be the net annual savings resulting from reduced energy costs. Other benefits could include a level of increased independence from the grid which might be of value to some consumers. However, this latter factor will probably not be of major importance in assessing overall market potential.

The most commonly used economic parameter used by consumers in considering the purchase of energy cogeneration equipment is the simple payback period defined by:

$$\text{Payback} = \frac{\text{(Incremental Initial Cost)}}{\text{(Energy Cost Savings - Incremental O\&M Costs)}}$$

The incremental initial cost is the installed cost of the cogeneration unit minus any credits which might apply by virtue of the cogeneration unit negating the need to purchase a conventional furnace or water heater. Such credits would, for example, apply if backup gas fired heating is integrated into the cogeneration system itself.

The incremental O&M costs are those which occur over the above those associated with conventional heating equipment. Conventional furnaces have minimal maintenance requirements (one servicing per year at most) which implies most of the O&M costs are in fact incremental, given the needs of currently available technology.

As indicated in Section 6, paybacks of no more than 4-5 years are required to attain initial market acceptance and of about 2-3 years to have significant market potential.

It should be emphasized that the installed cost is the critical cost parameter an seen by the consumer. One of the goals of a small scale cogeneration program will be to develop packaged modules which facilitate installation so that the allowable cost is primarily that associated with equipment.

5.1.2 Load Profiles

Cogeneration systems generally provide the best economic return when they are operated at a high capacity factor and have good overall utilization efficiency. Therefore, applications that have constant thermal and electric loads tend to be the most attractive applications. Load profiles vary with each application and have a marked effect on the economics. Specific load profiles were established for each of the building categories under investigation and are further discussed in the next section.

5.1.3 System Efficiencies

The baseline cogeneration system has an electricity generation efficiency of 25-30% and a thermal efficiency of 75-80% in recovering the remaining waste heat, for an overall conversion of fuel energy to useful thermal or electric energy of 86%, if all the thermal energy is used.

For systems sized to serve the hot water load, all the reject heat is utilized, efficiency has little impact on the savings realized per kW of electric capacity. However, for larger systems where there is some reject heat being dumped during the warmer months, the impact of efficiency is significant.

The most favorable cogeneration applications are those sized and operated such that all or most of the engine reject heat is used. In such cases the above discussion would suggest that engine efficiency, within reason, is not as important an operating parameter and improvements from current levels is not a high development goal.

5.1.4 Fuel Costs

Commercial natural gas costs for Ontario were based on the forecasts contained in the October 1986 Ministry of Energy publication The Outlook for Energy Prices and are contained in Appendix C.

5.1.5 Electrical Costs

Commercial electrical costs and buyback rates for Ontario were based on the forecasts contained in the October 1986 Ministry of Energy publication The Outlook for Energy Prices and the Ontario Hydro publication Parallel Generation Power Purchase Rates. The calculated costs and rates, taking into account both time differentiated and avoided cost based purchased rates, are contained in Appendix C.

5.1.6 Buyback Economics

The cogeneration system creates cost savings by generating relatively valuable electricity from relatively inexpensive gas. The purchase cost of the gas and the electricity is given. The selling price of electricity back to the utility varies by city and is a matter of continuing fluctuation at the time of this report. Since some cogeneration system schemes require electricity sellback to the utility, the price the utility will pay for the sellback electricity will have a major impact on the overall economics.

The maximum the electric utility is likely to pay for electricity, purchased from small scale cogenerators, is what the utility charges for electricity. This scenario would have a single meter that would run forward or backward. When running forward, the meter would register the kilowatt hours purchased by the customer exactly like an ordinary meter. When the customer sold electricity back to the utility, the meter would run backward. As long as there were a net sale of electricity to the customer, the billing for this meter would be exactly the same as for a standard customer. If there is a net monthly sale to the utility, the utility will pay the customer at the monthly average of the lowest cost block rates.

Another scenario requires two meters, one to register the electricity purchased by the customer and one to register electricity sold by the customer. Neither meter will move backwards.

These two scenarios are assumed to bracket the upper and lower rates the utility will pay the cogeneration system customer.

For the rest of this report, a $0.0375 kWh buyback rate is assumed. This is typical of the rates paid by Ontario Hydro for small scale cogenerators. (See Appendix C.)

5.1.7 Operating Costs

If O&M requirements for cogeneration units could be greatly reduced from current experience so that they represented no incremental cost over conventional equipment, the allowable costs for the cogeneration units to remain economically competitive would be in excess of $1,000 per kW, which is probably achievable with a combination of incremental improvements in current technology, careful system purchasing, and development of strong supporting organizations - possibly including the gas industry itself.

Realistically, however, cogeneration systems will always have incremental O&M needs as compared to conventional furnaces due to their inherently more complex mechanical configurations (engines, etc.) and control requirements.

The key questions revolve around the reductions in O&M needs required to result in favorable economics, and how this is affected by capacity.

The maintenance requirements will have to be reduced significantly below current levels to result in practical systems in this lower power range. The impact of O&M is, however, very sensitive to system size. At the higher end of the power range only modest improvements in maintenance costs would be required - say to about $0.75 per hour. However, at the lower end of the range corresponding to small commercial (1-5 kW), O&M costs will have to be reduced to below $0.20 per operating hour in order to result in viable systems.

The O&M costs are due both to routine maintenance (oil changes, filters, etc.) which are generally required every 500 to 100 hours for a reciprocating I.C. engine and the annualized costs of overhauls which occur every 10,000 to 20,000 operating hours.

The cost of routine maintenance calls are almost insensitive to engine size in the power range of interest. These costs are determined primarily by such factors as travel time, and office overhead, rather than the cost of consumables (oil, filters, etc.) which would be somewhat size dependent. Consequently, in the lower power range O&M costs tend to be dominated by routine maintenance procedures given the aforementioned need to visit systems at 500 to 1000 hour intervals, which implies up to 8-16 calls per year.

5.2 Economic Assessment

5.2.1 Procedure

A six step procedure similar to one developed by GRI (4) was used to estimate annual savings and simple payback for each case considered. A variety of cogeneration efficiencies, capacities, and operation schemes could be examined using this methodology. The steps are as follows:

.1 Select cogeneration technology and values for electrical capacity and equivalent full load operating hours.

.2 Calculate heating, cooling, and on-site electrical use factors from monthly data using Equations 1-3 in Table 5.1.

.3 Determine natural gas and average electricity prices and calculate value of cogenerated electricity using Equation 4.

.4 Use Equation 5-8 to estimate unit fuel cost, electricity income, heating income and cooling income.

.5 Subtract estimated fuel cost from incomes to determine unit annual net savings.

.6 Estimate the simple payback period for the range of unit installed costs and equivalent full load operating hours chosen, using the estimated net savings determined in Step 5.

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(4) "Simplified Evaluation of Commercial Buildings for Cogeneration Feasibility", Lawrence, T. Kostrezewa, Chicago, 1984.

TABLE 5.1 - EQUATIONS FOR ECONOMIC ASSESSMENT (25)

Number	Parameter	Equation
1	Heating Utilization Factor	$\frac{\text{(annual displaceable therms)}}{\text{(cogeneration kW capacity) x (T/E) x (EFLH)}}$
2	Cooling Utilization Factor	$\frac{\text{(surplus cogeneration output therms, cooling months)}}{\text{(cogeneration kW capacity) x (T/E) x (EFLH)}}$
3	On-site Electrical Utilization Factor	$\frac{\text{(annual displaceable kWh)}}{\text{(cogeneration kW capacity) x (EFLH)}}$
4	Cogenerated Electricity Value	(on-site elec. util. factor) x (retail electric rate) + [1 - (on-site elec. util. factor)] x (buyback rate)
5	Fuel Cost	$\frac{\text{(EFLH) x (.03412 therm/kWh) x (cogen. gas cost)}}{\text{(electrical efficiency)}}$
6	Electricity Income	(EFLH) x [(cogen. elec. value) - (O & M cost)]
7	Heating Income	$\frac{\text{(EFLH) x (T/E) x (heating util. factor) x (gas cost)}}{\text{(non-cogeneration heat source efficiency)}}$
8	Cooling Income	$\frac{\text{(EFLH)x(T/E)x(abs. COP)x(clg. util. factor)x(retail elec. rate)}}{\text{(electric-driven cooling source COP) x (.03412 therm/kWh)}}$

T/E = Thermal/Electric Output Ratio, therms/kWh

EFLH = Equivalent Full Load Operating Hours.

TABLE 5.2
SAMPLE DATA (5)

Month	Gas Use (Therms)	Displaceable Gas Use (Therms)	Electricity Use (kWh)	Displaceable Electricity Use (kWh)
January	1,430	1,430	117,900	41,500
February	1,180	1,180	109,500	41,500
March	1,070	1,070	121,300	41,500
April	740	740	117,900	41,500
May	630	630	126,300	41,500
June	200	200	117,900	41,500
July	150	150	131,400	41,500
August	110	110	124,600	41,500
September	210	210	114,500	41,500
October	480	480	112,700	41,500
November	700	700	107,800	41,500
December	1,200	1,200	104,400	41,500
Total	**8,100**	**8,100**	**1,411,400**	**498,000**

5.2.2 Sample Calculation

Monthly electricity and natural gas usage data for a sample building, a moderate-sized supermarket has been collected and is presented in Table 5-2. In addition, it is known that the facility is occupied 8760 hours per year. The average rate paid by the facility for electricity is $.05/kWh, and the buyback rate is $.0375/kWh. The natural gas price is $0.35/therm. Following the steps:

1. For the initial case, a reciprocating gas engine cogeneration system will be assumed, with a capacity of 60 kW. Annual equivalent full load operating hours will be assumed at 8300, allowing for maintenance downtime.

   Electrical and overall efficiency, maintenance cost, and ratio of thermal to electrical energy output are shown in Table 5.3. Given these parameters and, natural gas and electricity price information, it will be possible to determine the simple payback periods that will result from the range of installed costs of a cogeneration system.

2. Waste heat utilization for heating is determined using Equation 1. Before applying Equation 1, "annual displaceable therms" must be found from the monthly data by subtracting out non-displaceable uses, such as cooling or decentralized heating. (In this example, all of the annual total is displaceable, amounting to 8100 therms/year). The resultant monthly loads met by cogeneration will be the lesser of either the actual load or the maximum amount the cogeneration system can deliver, in this case 3029 therms/month (60 kW x 0.073 therms/kWh x 8300 hours/12 months).

TABLE 5.3 COGENERATION EQUIPMENT PARAMETERS

Thermal/Electric Ratio (therms/kWh)	0.073
Electrical Efficiency (% HHV)	26
Overall Efficiency (% HHV)	75
Absorption COP	0.7
Maintenance Cost (cents/kWh)	1.0

Existing energy equipment is assumed to have a 75% fuel to heat conversion efficiency and a 3.0 COP on electric-driven cooling equipment.

Using Equation 1, the heating utilization factor is:

$$\frac{8100 \text{ therms}}{60 \text{ kW} * 0.073 \text{ therms/kWh} * 8300 \text{ hours}} = 0.22$$

A surplus of 28248 therms is available from the cogenerator that is not used for heating. If used to provide cooling through an absorption chiller, the cooling utilization factor is found using Equation 2:

$$\frac{28{,}248 \text{ therms}}{60 \text{ kW} * 0.073 \text{ therms/kWh} * 8300 \text{ hours}} = 0.78$$

The on-site electrical utilization factor is determined in much the same way. The monthly on-site electrical loads met by cogeneration will be the lesser of the actual load or the maximum amount the cogeneration system can deliver, in this case 41,500 kWh/month (60 kW x 8300 hours/12 months). These sum to 498,000 kWh, as shown in Table 2. Using Equation 3, the on-site electrical utilization factor is:

$$\frac{498{,}000 \text{ kWh}}{60 \text{ kW} * 8300 \text{ hours}} = 1.00$$

3. The average value for cogenerated electricity will depend on what fraction displaces on-site purchases at the retail rate, and how much is sold to the utility at the buyback rate. Using Equation 4, the result for this example with no buy-back is 5 cents/kWh.

4. Using Equations 5-8:

Fuel Cost: 8300 * 0.03412 * $0.35 / 0.26
yields - $372/kW/yr

Electricity Income: 8300 * (.05 - .01)
yields $324/kW/yr

Heating Income: 8300 * 0.073 * .22 * $0.35 / .75
yields $61/kW/yr

Cooling Income: 8300 * .073 * .7 * .78 * .05/(3*.03412)
yields $157/kW/yr

5. Estimated net savings: = -372 + 324 + 61 + 157 = 170
Net savings come to $170/kW/yr or $10,200/yr for the 60 kW system.

6. Using the same values simple paybacks ranging between 5.8 and 8.2 years will be seen for installed costs between $1000 and $1400/kW.

Additional iterations using different technologies and different capacity and operating hour selections were performed in order to gain an understanding of what cogeneration configuration would be most suitable for the application being analyzed. For example, further analysis showed that a smaller (15kW) system, would save $197/kW/yr even without cooling due to greater utilization of heat for heating. Total annual savings for the smaller system would amount to a lower $3,000 but would payback in 4.0 to 6.0 years for installed costs between $800-$1200-kW (about $200/kW lower because no absorption chiller would be needed). Conversely, larger systems which generate an additional electricity income by selling back to the grid would require additional installation costs for the switchgear.

5.3 Sensitivity Analysis

The preceeding section outlined the economic analysis performed for the various buildings and cogeneration systems under investigation in this report. In each case the results were relatively similar: Payback periods of from four to ten years were typical. Even when escalating fuel costs, capital cost allowance, and Class 34 depreciation are taken into consideration, the "acceptable" payback periods of two to three years are not realized.

The only item with appreciable impact on the economics is a reduction in the installed cost (and to a lesser extent maintenance cost). These cost reductions can come about via a number of methods: primarily due to economies of scale or advances in packaged cogeneration technology on the part of the manufacturers, but also through grants or project assistance by the Government. As it is likely that the former will be the determining factor it is expected that economically feasible commercial cogeneration is approximately ten years away.

6.0 BUILDING OWNERS' AND OPERATORS' REQUIREMENTS

6.1 System Characteristics Preferred by End User

The purpose of the consumer analysis is to develop system packages preferred by consumer groups. These packages will give guidance to the process of assessing technical feasibility and technology readiness. The goal in the consumer analysis is first to determine the benefits provided by cogeneration systems as preferred by our consumer groups; second to determine any constraints placed on cogeneration system packages by consumer needs or physical factors; and third to relate these benefits and constraints to specific cogeneration system features and functions.

Most potential purchases of commercial size systems in the 30 - 100 kilowatt range are not as interested in a grid independent system than are potential large system purchasers. This concern with the ability to create a grid independent system is true most useful in applications where backup power systems are required. A cogeneration system could substitute for an otherwise required standby power generator, provided that additional code requirements for fuel supply, etc. are met. Most other features are of relatively limited importance in the commercial sector; provided that no feature, such as noise or emissions, is excessively worse than conventional practice.

One serious issue facing acceptance of cogeneration systems in light of commercial applications is the small proportion that energy costs are of total costs in most applications. Further, a 30-100 kilowatt cogeneration systems will provide only a modest savings in total energy costs. In a number of applications, the return on investment created by a cogeneration system is somewhat attractive, but the total savings in absolute dollars, may be such a small proportion of total energy costs and a small absolute dollar figure to limit interest in the cogeneration system.

A great deal of research has been carried out over the past several years by GRI, on acceptable levels of payback periods for a wide variety of energy conserving devices. Several basic characteristics of financially related decision making processes have become clear from this accumulated research. First, payback periods are a simple, useful tool for assessing economic attractiveness of an energy conserving technology. Examples of payback periods versus anticipated market acceptance for decisions made by commercial building owners are shown in Figure 6.1. While more sophisticated financial measures, such as life-cycle costing or discounted cash flows may give more subtle renderings of economic performance, payback periods are simple, easily calculated measures and, more significantly, provide an accurate model of consumer's purchasing patterns.

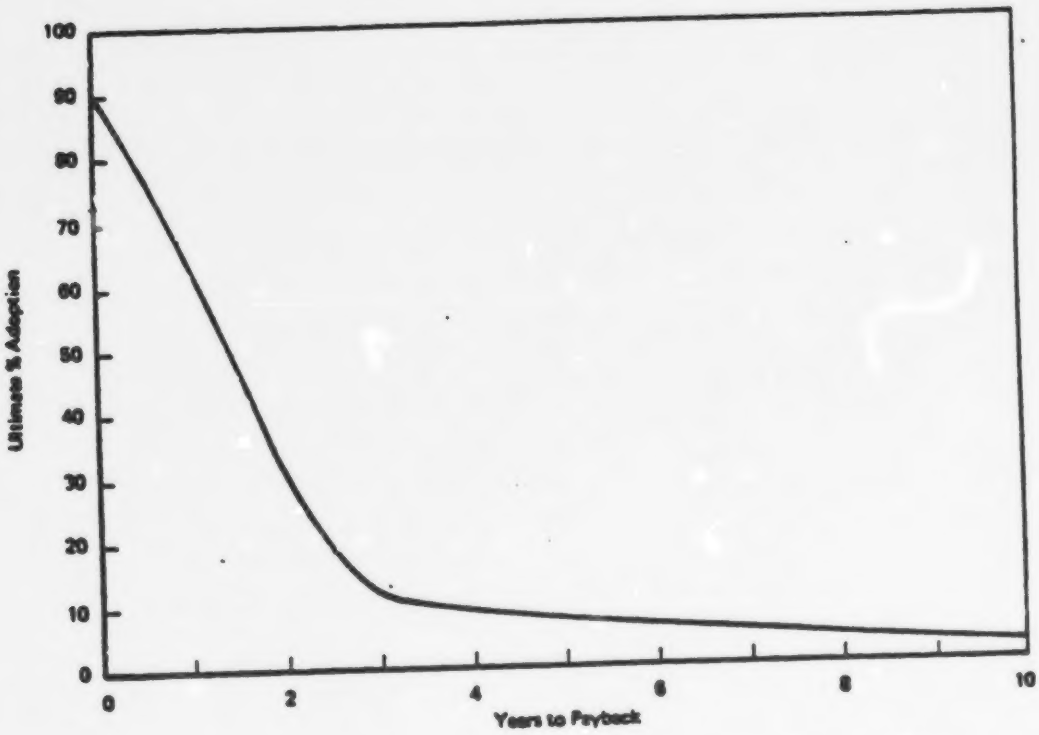
The acceptable number of years to system payback declines as the absolute cost of the conservation device increases and as the perceived risk inherent in the technology increases. For new products whose incremental cost is a larger portion of the total installed cost (50%), the required payback period will be much shorter than if the incremental cost is a small portion (10-20%) of the total cost.

Similarly, simple technologies can have longer acceptable payback periods than will less familiar, less readily understood more complex products.

6.1.1 Unit Location and Dimensions

The question of location for a cogeneration system is initially a technical and practical one based on the availability of space and the need to tie the cogeneration system into existing HVAC and plumbing systems. Within these spatial and logistical constraints, it becomes a consumer response issue, based on desires and perceptions. Technical considerations tend to eliminate certain possible applications, especially for distributed cogeneration systems designed to serve individual rooms in a hotel or the

FIGURE 6.1 MARKET PENETRATION RATES (29)



like. In these applications, there simply is not space available in convenient locations which could, in a practical sense, be devoted to a cogeneration system.

Most cogeneration systems will need some capability to exhaust unusable heat, a process which will probably entail at least one liquid-to-air heat exchanger located outdoors. Once any major component and associated piping is located through an external wall, there may not be a substantial cost penalty to locate all of the major components outdoors. Such an outdoor location will mitigate substantially any consumer concerns over system noise and other service and maintenance logistics.

Most commercial buildings have mechanical or utility rooms which are, in practice, acoustically isolated from occupied areas and which have some surplus room. Outdoor locations, however, are generally not available. The building perimeter is often constrained by walks, driveways, parking areas and the like. Further, roofs for light commercial facilities are not usually designed to accept the vibrating load of a cogeneration system. Consequently, commercial cogeneration systems will tend to be located indoors, in areas where space availability and other factors, such as noise, are not serious constraints.

6.1.2 Noise

Noise produced by a cogeneration system only becomes an issue when it is unacceptable; a system is either acceptable or it is too noisy. In general, consumers are opposed to any increase in the general noise level perceived in their general environments and from their heating and air conditioning equipment. Noise is also a largely personal issue, thus the noise level perceived by building occupants is, at least initially, more important than any noise that may be perceived by non-occupants outside of the building.

6.1.3 Emissions

As long as emissions are not perceivable by human senses and are not restricted by regulations, they will not present a problem. For a natural gas powered cogeneration system, the particular emission issue is NO_X and not sensorily perceivable smoke or odors such as those produced by oil or solid fuel systems. However, the problems associated with the NO_X emissions are becoming more widely understood and of greater concern to a variety of regulatory authorities. Therefore, it is possible the NO_X regulations may be developed within the product development time horizon for cogeneration systems.

6.1.4 Maintenance

Insuring adequate maintenance on cogeneration systems will be a critically important aspect in the design of acceptable cogeneration packages. In light commercial applications, typical preventative maintenance practices are extremely poor and no staff is generally available to monitor or maintain equipment. Consequently, cogeneration packages must be designed with the assumption that facility operators will not perform any necessary preventative maintenance and repair functions. Outside service organizations (manufacturers, utilities, independent service companies, etc.) will be necessary. Furthermore, the requirements for preventative maintenance and expected degree of repair must fit within both the economic constraints posed by the available energy savings and within the limits of consumer acceptance. The relatively easy access to mechanical rooms and the general acceptance of service personnel will make service and maintenance of cogeneration systems a matter of economic viability rather than a situation constrained by consumer desires.

Service and maintenance issues will depend on the cash-flow available from energy savings consistent with payback requirements. For systems where structural factors do not constrain the number of maintenance calls, the key element in system design will be to minimize the cost of maintenance per kilowatt-hour produced.

6.2 Barriers to Implementation

As outlined in previous reports on barriers to implementation of cogeneration in Ontario (5), the major consumer concern with cogeneration technology is its' current economic situation. As mentioned earlier, current cogeneration technology exhibits 4 to 10 year paybacks, where, typical acceptable payback periods are 3 to 5 years.

Another barrier, though not perceived by the consumer, is the consumers' general lack of knowledge of what cogeneration systems are, and have to offer. If the technology were less of a mystery to the consumer then, as described earlier, they would be more willing to accept it (and perhaps be willing to accept longer payback periods).

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(5) Cogeneration Potential in Ontario and Barriers to its Implementation, prepared for the Ontario Ministry of Energy, by Acres International Ltd., February 1987.

7.0 SUMMARY AND CONCLUSIONS

Natural gas-fueled cogeneration offers numerous benefits for the gas consumer, gas industry, electric utilities and province as a whole. Energy and cost savings for the cogeneration user coupled with the resultant utility load leveling and improved utilization of the gas transmission system, results in lower energy costs.

The nature of applying cogeneration to commercial buildings differs substantially from industrial applications. Unless a very large hot water heating load is found, it is necessary to consider the cogeneration system essentially as a heating/ventilation/air conditioning (HVAC) system, supplying electricity, heating, cooling, and domestic hot water as required. As an HVAC option, cogeneration can be particularly attractive in the new and replacement market where displaced emergency electric generation and HVAC equipment costs can act as a credit. Total packaged systems, whose only installation costs entail site preparation and a few plumbing and electrical hookups, are often attractive and can help such HVAC applications to be cost-effective and reliable.

In general, retail electricity prices to commercial customers are considerably higher than those charged to industrial customers. To a large extent, this can make up for the fewer operating hours seen in a commercial application. The large numbers of buildings in these sectors could permit factory assembly of standardized packages containing the engine, generator, heat recovery, chiller, and ancillaries. Economies of mass production could be as significant as those of scale. These factors, coupled with the slightly longer payback periods considered acceptable in commercial sector (3-5 years, as opposed to the 1-3 years typically required by industry), can make the economics fairly attractive. Financing, too, becomes less difficult due to the considerably lower capital investment required for these smaller systems.

In a system designed to meet commercial heating and cooling loads, the electricity cogenerated will generally not exceed that required by the application. This avoids the often difficult and costly interconnection and negotiation of purchased power agreements and uncertainty associated with buyback rates.

The current technology available for commercial size cogeneration combined with current energy costs, however does not make cogeneration a feasible alternative for Ontario. It is expected that this situation will not change for at least ten years.

7.1 Key Market Potential

There are many applications in the commercial sector which have sufficient electric and thermal loads (cooling loads can be met by waste-heat-driven chillers) to make cogeneration economically attractive. These applications include, restaurants, hotels/motels, health clubs, laundries and supermarkets.

7.2 Critical Factors for Success

An acceptable payback target for initial market introduction will be three years, with an ultimate target of two years. Again, any shorter period will be highly beneficial. While these payback periods appear extremely short and, thus, highly demanding on technologies, the practical affect in some applications may not be so onerous. Where a cogeneration system can substitute for a stand-by generator, the incremental capital cost of the cogeneration system will be smaller, making short payback periods easier to achieve. Some commercial facilities such as hotels or bars also value the ability to operate in the event of failure in the electric grid, yet are not willing to buy stand-by systems. In some instances, these owners may accept a longer payback period coupled with increased power reliability.

Projected fuel costs alone are not expected to improve the economic potential for commercial applications. It is improvements in the technology, and the emergence of new and less costly technologies, that will make cogeneration acceptable in the future.

Utilities can have some impact in the penetration of commercial cogeneration: The electric utilities could ease the difficulties regarding electric grid interconnection and increase the negotiated buyback rates. While gas utilities could provide consumers with gas sales contracts which set a lower gas rate for cogeneration uses.

8.0 RECOMMENDATIONS

Given the current market situation, the Ministry of Energy could assist in the development of commercial cogeneration in two areas.

Firstly, the Government could encourage the use of cogeneration in commercial application through the use of grants or demonstration projects. This (short term solution) would help individuals to overcome the economic barrier to implementation, but more importantly it would allow the technologies to develop and improve into feasible alternatives.

Secondly, and subsequent to the first recommendation, the Ministry could embark on a program of technology transfer which would promote cogeneration to the potential consumer by relating the information obtained during the demonstration programs. This would increase the awareness of the technology among the user community and overcome the second major barrier to its' implementation.

Finally, it is recommended that the market be monitored for the trends in new product development and other factors discussed in this report. A simple economic evaluation such as outlined here could be performed at some future time to reassess the potential for commercial cogeneration in Ontario.

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APPENDIX A

COMMERCIAL COGENERATION RESEARCH AND DEMONSTRATION PROJECTS

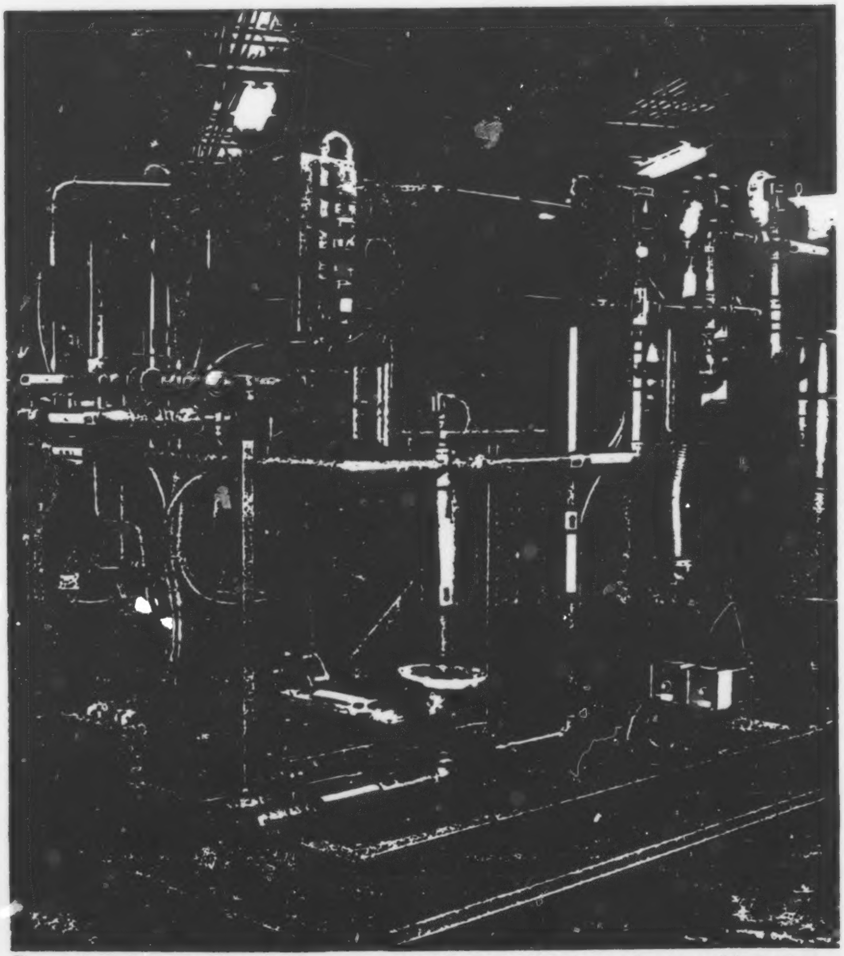
Gas Research Institute August 1986

TECHNOLOGY PROFILE

Small Commercial Cogeneration/HVAC System

Problem

Commercial establishments such as nursing homes, motels, and restaurants, experience very high energy costs. When these facilities have sufficient operating hours and electrical loads and can usefully employ an engine's recovered heat, a packaged cogeneration system offers an economically viable alternative to conventional energy service. In these small buildings—typically under 10,000 square feet—space conditioning requirements rather than domestic hot water generally represent the predominant and most expensive thermal load.



The packaged cogeneration/HVAC system makes the most efficient use of energy while meeting the energy service priorities of the small commercial user.

GRI Solution

A properly sized packaged cogeneration system that provides the necessary mix of energy services can optimally meet the energy requirements of many small commercial users. With funding from GRI, Waukesha Engine Division of Dresser Industries, Inc., and Gas Energy, Inc., are developing a 70kW packaged cogeneration/HVAC system. It incorporates a Hitachi PARAFLOW™ absorption chiller/heater that effectively recovers and uses engine heat to meet the space conditioning requirements of smaller commercial buildings.

Benefits

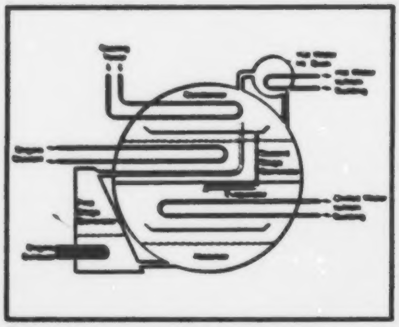
By using natural gas to generate electricity and sequentially provide useful heating or cooling, the packaged commercial cogeneration/HVAC system provides consumers with lower overall energy costs through more efficient energy service. The system could save $15,000 to $30,000 per year in operating costs depending on local energy prices, application, and climate, when compared to conventional heating and cooling equipment. As an HVAC option, cogeneration is attractive in the new and replacement market where displaced HVAC equipment costs may be taken as a credit. Additionally, the increased demand for natural gas through the use of cogeneration on a year-round basis offers a stable nonseasonal gas utility load and reduces costs to all gas consumers.

Concept

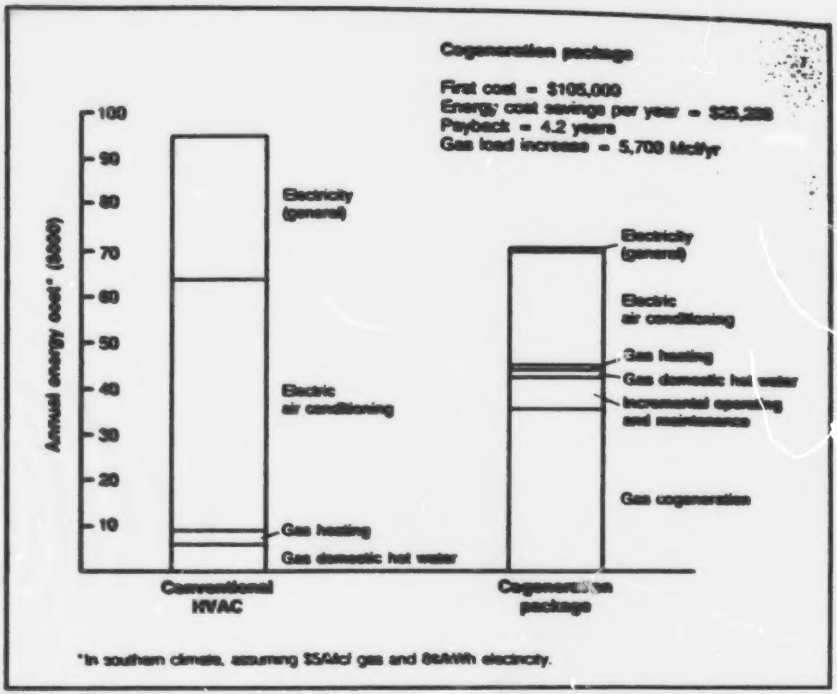
The skid-mounted, factory-assembled package incorporates a Waukesha 70kW engine/generator set that features low-pressure gas induction, which allows increased turbocharging for higher power output without the need for an expensive fuel-gas compressor. Because the engine exhaust temperature is higher than that of previously available engines, higher temperature heat can be recovered, allowing for more effective use of energy for cooling.

The system's absorption chiller/heater combines the functions of engine heat recovery and production of hot or chilled water. This arrangement reduces the amount and complexity of system hardware. Double-effect design boosts the chiller/heater's cooling capacity to 40 tons. While operating in the heating mode, the unit delivers 400,000 Btu per hour. Using heat in the absorption chiller to provide cooling as well as heating increases the overall value of the cogeneration system and significantly reduces purchases of electric power during warm weather for air conditioning.

The system also includes a gas-fired boiler to provide back-up heating and cooling when the engine is being serviced. With this supplemental capacity and flexibility, the engine and boiler can be run together on the coldest days when the engine itself does not provide enough heat.



The system incorporates an absorption chiller/heater.



*In southern climate, assuming $5/Mcf gas and 8¢/kWh electricity.

Energy cost savings.

Project Status

The packaged system was designed following a detailed feasibility study that analyzed operating data on numerous commercial applications throughout the United States. Based on this analysis, specific components were developed and tested to meet the performance requirements for the package. Work is continuing to reduce the first cost of the packaged system and to simplify the package's interface with energy distribution systems in buildings.

The components modified and enhanced specifically for this package, the engine and the absorption chiller/heater, have already gained commercial success and point toward the viability of the package as a whole. Since June 1985, a number of heat recovery chiller units have been sold by Gas Energy, Inc. Waukesha has sold engines individually for hot water-only cogeneration packages.

To confirm the capabilities of the packaged system and identify obstacles to its successful commercialization, a field test began in June 1986 in conjunction with Beverley Enterprises at their Park Lake Nursing Home in Winter Park, Florida.

Prospectus

Based on the results of a successful field test, advances in component technology will be incorporated into the package design which should further reduce the system's cost and complexity. The large number of potential applications for this system may allow mass production of the package, further reducing installed costs. If cost-reduction efforts are successful, Waukesha plans to add the package to its cogeneration system product line as early as 1987.

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GRI

Gas Research Institute February 1987

TECHNOLOGY PROFILE

Supermarket Cogeneration Package

Problem

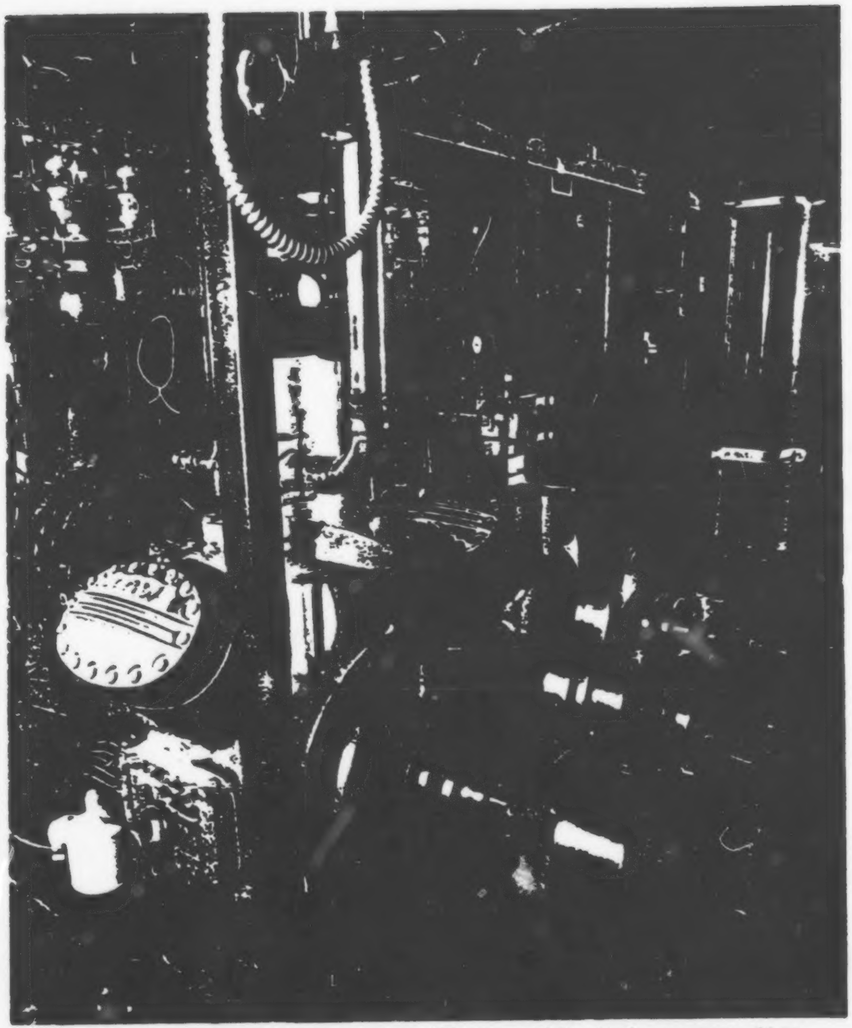
Although supermarkets are fairly small gas users, they do have the large, continuous energy demands necessary for cogeneration to provide economic benefits. Moreover, supermarket managers are highly motivated to save energy since it represents one of their largest controllable operating expenses. In a typical supermarket, the refrigeration system accounts for 54 percent of the energy consumption costs. A cogeneration package, tailored to provide the shaft power required for supermarket refrigeration, would provide an attractive opportunity to reduce energy costs.

GRI Solution

Foster-Miller, Inc., under contract to GRI, is developing a packaged supermarket cogeneration system that differs from most other cogeneration packages in that the gas-fueled engine's shaft energy primarily drives refrigeration compressors instead of an electrical generator. It provides 100 percent of the store's compressor-driven refrigeration needs on a continuous basis, while supplying most of the store's space heating load and some electricity.

Benefits

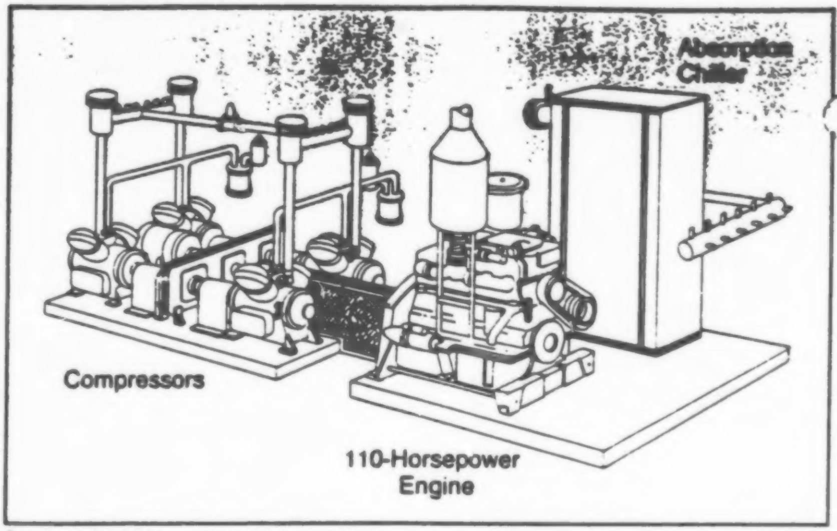
For the typical supermarket of 30,000 square feet, energy savings of approximately $20,000 to $40,000 per year are expected, depending on local energy prices and climate. A payback period of 1.5 to 3.5 years is expected on incremental system costs relative to conventional electric compressor systems. At the same time, the increased demand for natural gas through the use of cogeneration on a year-round basis offers a stable, nonseasonal gas utility load and reduces costs to all gas consumers.



The supermarket cogeneration package provides 100 percent of the store's compressor-driven refrigeration needs on a continuous basis.

Concept

The skid-mounted unit incorporates a 110-horsepower Cummins gas-fueled engine that drives a bank of four Carrier open-shaft reciprocating refrigerant compressors. By using direct mechanical drive, the system is more efficient than engine/generator sets and capitalizes on the flexibility afforded by variable engine speed. System waste heat is used to provide space heating or to drive a 10-ton Yazaki absorption chiller, which subcools the refrigerant liquid to increase system capacity, and also provides some space cooling. The package also includes a 125-horsepower induction motor to assure full reliability in providing refrigeration to the perishable food, even when the engine is shut down for maintenance. During cool weather when full compressor power is not required but space heating demand is high, the same motor serves as a generator, driven by the engine to supply electricity for store lighting.

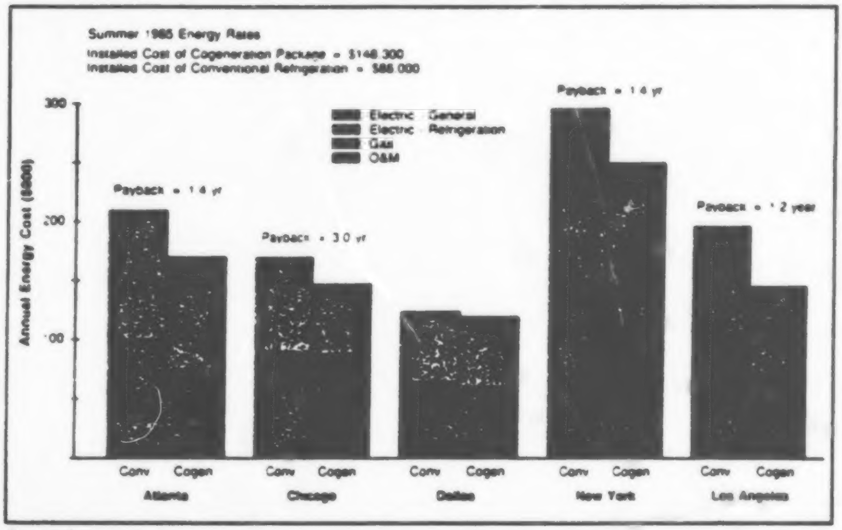


System schematic.

Project Status

Beginning in October 1985, Foster-Miller tested the cogeneration package prototype in the laboratory. The package was then shipped to the field test site at a new supermarket in Los Angeles. Kimmel-Motz Refrigeration Corp. worked with Foster-Miller in the design and installation of the package for the 12-month field test which began in August 1986. With the assistance of Southern California Gas Company, the unit is being monitored for operating reliability and verification of its overall economic viability.

In the course of this project, it has also been determined that the system has enough high-quality surplus heat available to regenerate a desiccant dehumidifier in the cooling season. To test this concept, a second field test is planned for mid-1987 to couple the cogeneration package with a commercially available SuperAire® integrated dehumidification/air-conditioning unit which was developed by Cargocaire Engineering Corporation with GRI support.



Payback period.

Prospectus

Following a successful field test, Kimmel-Motz intends to commercialize the supermarket cogeneration package in late 1987. Because of the attractive paybacks in many parts of the country, the supermarket package could extend the cost-saving benefits of gas-fueled cogeneration to the approximately 3000 supermarkets that are opened or remodeled each year.

For Further Information, Contact:

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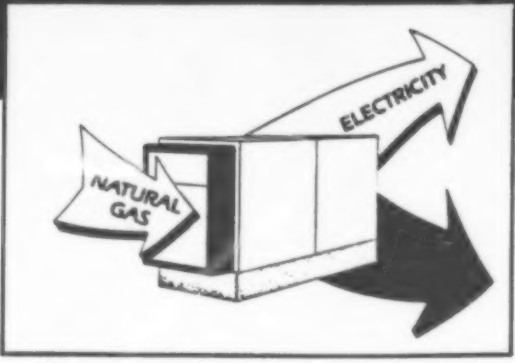
APPENDIX B
PACKAGED COGENERATION SYSTEMS DATA

PACKAGED COGENERATION

22 kW
TELEDYNE
TOTAL POWER
POWER

TELEDYNE
TOTAL POWER

The principle of cogeneration begins with the highly efficient Continental TM industrial engine. This engine burns natural gas, which in turn drives an induction generator to produce electrical power. The heat from the engine is transformed into useful thermal energy in the form of hot water. This results in an overall energy efficiency of greater than 90%! Making the most of your energy dollar is what cogeneration is all about!



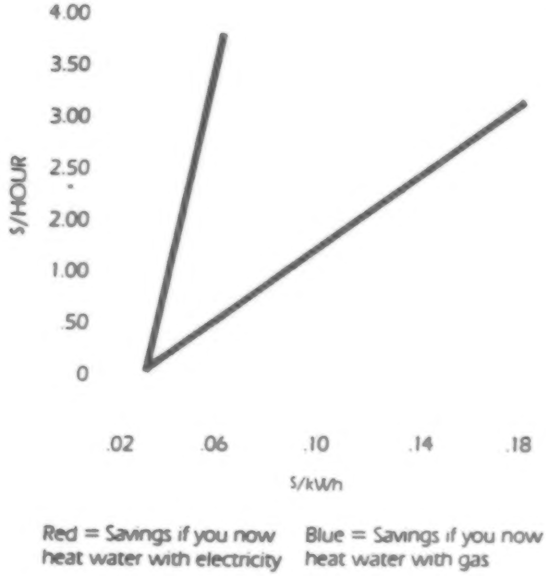
The Teledyne **TOTAL POWER** cogeneration unit is complete and fully operable when delivered to you. The unit is small enough to pass through a normal 36" wide doorway. The low noise level, 72 decibels at 3 feet, and attractive appearance allow the unit to be located practically anywhere. To install, simply connect your fuel line, water inlet, hot water outlet, exhaust, and electrical connections, then turn the key to the "on" position.

The **TOTAL POWER** unit produces 22 kW per hour of electrical power and 187,000 BTU's per hour of hot water. This hot water is delivered at a rate of 16 gallons per minute with a temperature rise of 24°F (184°F max).

Service-minded engineering ensures long life and easy maintenance. The doors fold back and slide off, allowing access to all internal components. A self-diagnostic system alerts service personnel of problems with the engine or the electrical system. Full system protection is provided to prevent damage in hazardous situations.

COGENERATION SAVINGS

Electrical Rate vs. Savings Per Hour



Cogeneration is cost effective! The table below compares conventional energy costs with those of the **TOTAL POWER** cogeneration unit. We estimate that you could save over $1.31 per hour of energy use. At 6500 hours per year of operation, your savings would exceed $8500 annually!

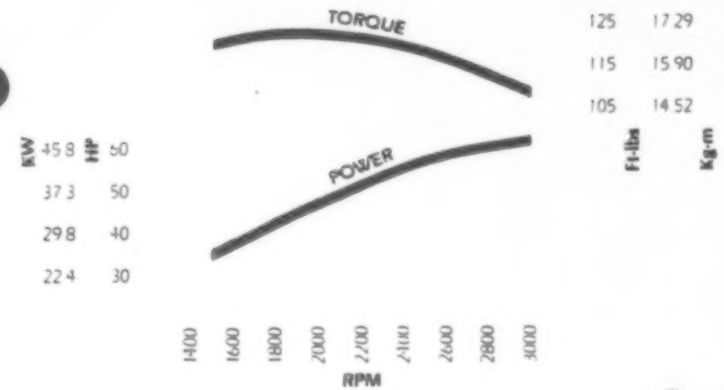
Your savings will depend on electrical rates, hours of operation and whether you are currently heating water with gas or electricity. If you are now heating water with electricity, the hourly savings with the Teledyne **Total Power** unit would be much higher. It is possible in some areas to obtain a special cogeneration rate for natural gas, which would increase your savings.

22 kW of electrical power @ 0.09/kWh	$1.98
261,800 BTU/hr of gas @ $0.60/therm to provide 187,000 BTU of hot water from a 60% efficient water heater	$1.57
CONVENTIONAL COST PER HOUR	$3.55

Maintenance cost per hour	$0.40
3.07 therms/hr gas @ $0.60/therm	$1.84
COGENERATION COST PER HOUR	$2.24

The market-proven Continental TM27 engine provides thousands of maintenance-free hours of operation. Designed specifically for heavy-duty industrial and material handling operations, the TM27 delivers outstanding reliability, performance and longevity. The first totally metric industrial machine built entirely in the U.S.A., the TM27 engine solves equipment and maintenance designers' problems in the metric world of the late 80's and 90's.

The packaged cogeneration units are proven by more than three years of operating results. Many applications, including nursing homes, dormitories and swimming pools, have produced operating results of 20,000 hours.



The power curves on the left show maximum dynamometer brake horsepower of the basic engine, corrected to a pressure reading of 29.3 in. Hg (99 KPA) dry barometer and temperature of 77° F (25° C) when tested in accordance with SAE Test Code J1349. Engine output can be demonstrated within 5% at the factory under standard rating conditions. Power will decrease 3% for each 1,000 ft. (305M) above 500 feet and 1% for each 10° F above standard temperature of 77° (25° C). For continuous operation, applications should be limited to 80% of power shown.

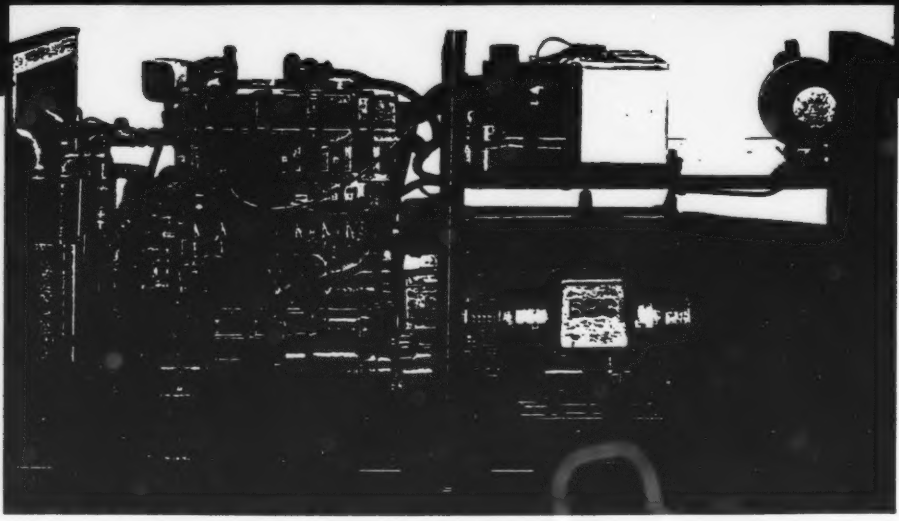
1500	33.7	25.1	118.0	16.3
1600	37.3	27.8	122.4	16.9
1800	44.0	32.8	122.6	17.0
2000	46.7	34.8	122.6	17.0
2400	54.4	40.6	119.0	16.5
2800	60.0	44.8	112.5	15.6
3000	61.8	46.1	108.2	15.0

Engine

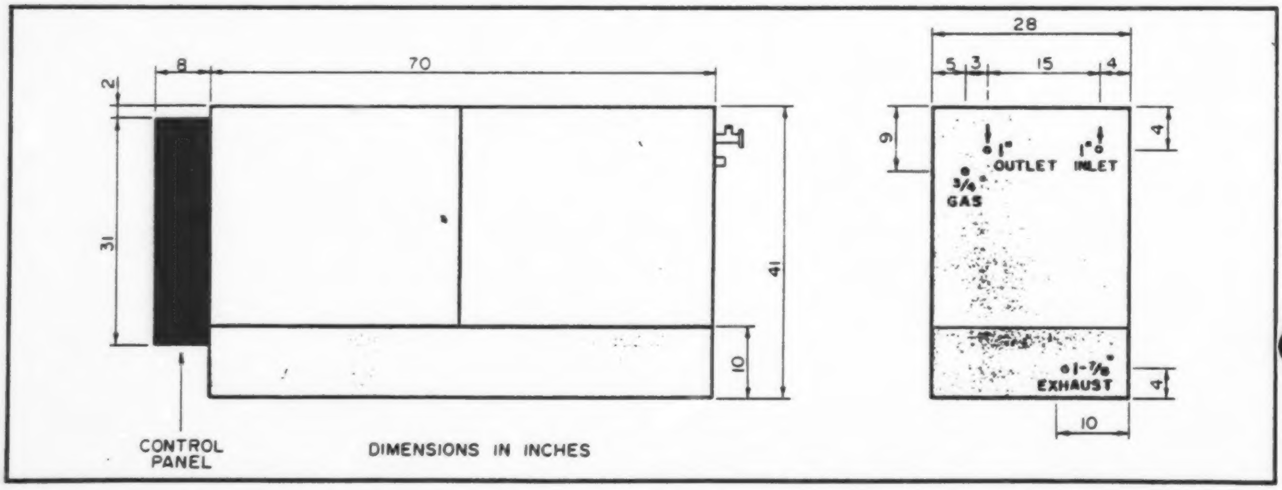
Engine type . . . . . In line 4 cylinder natural gas* 4 cycle OHV
Bore and stroke . . . . 91 x 103.2 mm
Displacement . . . . 2.7 liters
Maximum speed . . . . 3000 rpm
Maximum horsepower . . . . 60.5 (45 kW)
Maximum torque . . . . 120 ft. lbs. (163 Nm)
Number of main bearings 5
Weight of standard engine including accessories . . . . 536 lbs.
Operating speed . . . . 1840 rpm

*LPG, diesel and gasoline versions available.

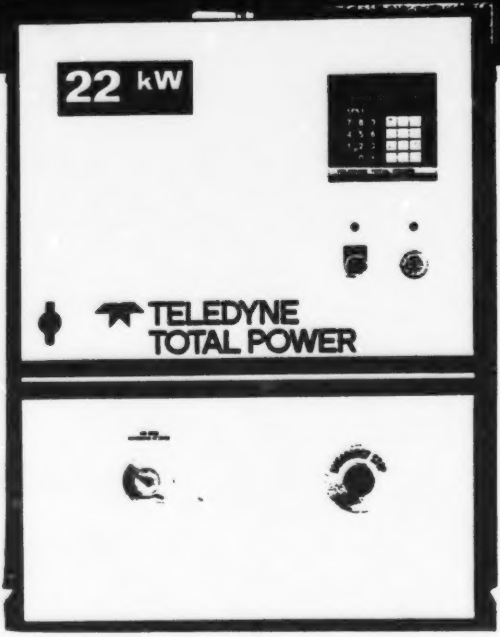
The Total Power Unit has panels that can be removed for easy maintenance and complete accessibility. This unit produces 22kW per hour of electricity and 187,000 BTU's per hour of hot water.



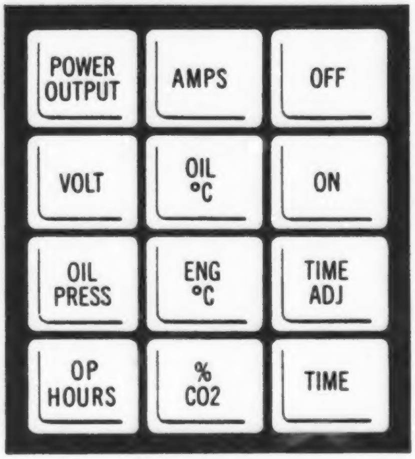
Electrical Output	22kW
Electrical Voltage Output	120/208 3 Phase
Duty Cycle	Continuous
Noise Level	72 dB @ 3 ft.
Operating Temperature	−20°F to 120°F
Fuel Source	Natural or LP Gas
Fuel Consumption	3.07 Therms/Hr
Usable Heat Generated	187,000 BTU/Hr
Specific Gas Consumption (Full Load)	13,347 BTU/kWH
Total Air Intake Flow	5717 cu. ft./Hr
Engine	Teledyne Continental TM27
Compression Ratio	8:3:1
Oil Pan Capacity	16.5 qts.
Size	78" long x 28" wide x 41" high
Shipping Weight	2,000 lbs.


8
70
2
31
41
10
CONTROL PANEL
DIMENSIONS IN INCHES
28
5
3
15
4
9
4
1"
OUTLET
1"
INLET
3/4"
GAS
1-7/8"
EXHAUST
4
10

The control system incorporates a microprocessor to provide protection, alarms and measurements. A digital display allows the operator instant access to the measurements listed below. The display is also used to indicate problems and aid in trouble-shooting.



KEYPAD SELECTIONS



PROTECTION FEATURES

- Under/Over Voltage
- Under/Over Frequency
- Under/Over Power
- Under/Over Speed
- Oil Pressure, Temperature & Level
- Water Pressure & Temperature
- Phase Asymmetry & Sequence

INDUCTION GENERATION

When an induction generator is driven above its synchronous speed while receiving AC excitation from the line, it will generate real power. This process is also called asynchronous generation. The asynchronous generator cannot generate reactive power; in fact, it requires reactive power from the utility to furnish its excitation. In other words the induction generator will not generate power unless the utility line is connected and energized. No synchronization equipment is necessary. Induction generation is the simplest form of parallel operation with utility power grids.

HEAT RECOVERY

Heat is transferred from the combustion process to a liquid coolant which is circulated through the engine jacket, oil cooler and exhaust system. This circulation path is a closed system, internal to the module. The heat transfer from the internal coolant to external water is accomplished using a plate-type, stainless steel heat exchanger.

There are many ways to apply the **TOTAL POWER** cogeneration unit. The hot water output can be used for space heating, for heating swimming pools or spas, for laundry water or shower water, or to drive an absorption chiller for air conditioning.

This makes cogeneration attractive to the owners or operators of:

- Hotels and Motels
- Laundries
- Health Clubs
- Green Houses
- Apartments
- Nursing Homes
- Schools and Colleges
- Hospitals

TELEDYNE TOTAL POWER

Headquarters
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P.O. Box 181160
Memphis, Tennessee 38181-1160
Phone: (901) 365-3600
TELEX: 462-1058 (ITT)
Call Toll Free: 1-800-932-2858

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Belgium
Phone: (32) (41) 67 53 20
TELEX: 42361 TDY TP B

Printed in USA

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TECOGEN®

CM-60 Cogeneration Module

Community Linen Rental Service, Inc. Los Angeles, CA

The TECOGEN CM-60 module offers commercial, institutional and light industrial facilities the opportunity to take advantage of the benefits of cogeneration. The complete, factory assembled and tested cogeneration system provides 60 kW of electricity and 440,000 Btu's per hour of hot water. When larger energy requirements need to be met with a high degree of flexibility, facilities may choose to install multiple CM-60 modules rather than one of Tecogen Inc.'s larger cogeneration modules. The fully integrated package is available for quick delivery (often from stock) and the proven standardized design enables rapid site engineering, permitting, low cost installation, start-up, and maintenance. The high efficiency of the system assures quick payback (2 to 4 years) and excellent return on investment.

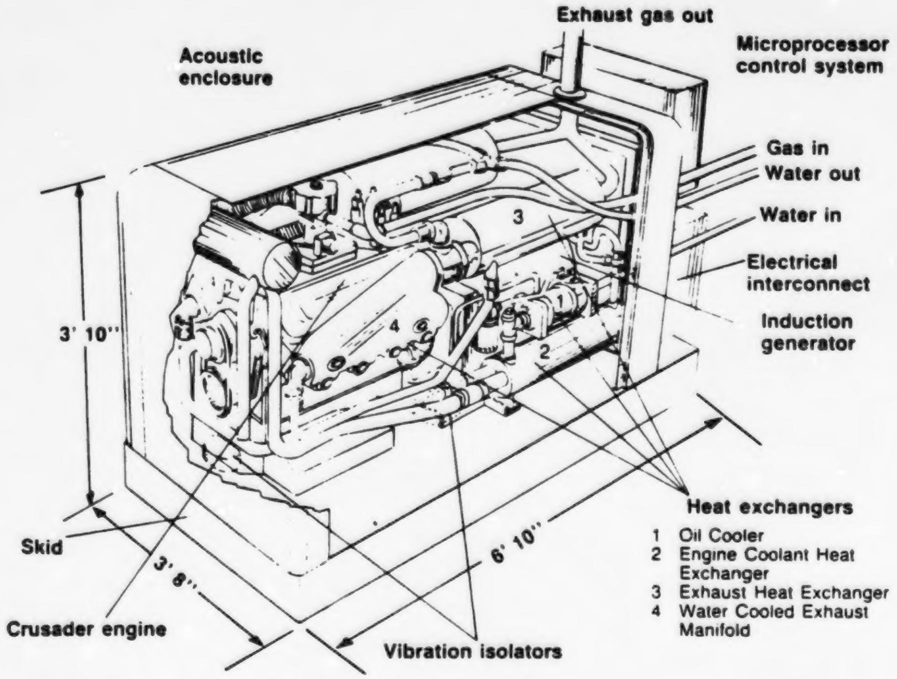
The TECOGEN CM-60 module offers the user:

- Improved facility operation with decreased operating costs.
- Siting flexibility, due to the compact, skid-mounted, vibration isolated design with attractive acoustic enclosure for quiet indoor or outdoor (optional) use.
- Unattended operation and fast diagnostics through utilization of microprocessor controls.
- Equipment designed for maximum availability, translating to optimized energy savings and reliable operation.
- Electrical switchgear for parallel operation.
- A complete cogeneration package from one supplier, with the same quality of engineering, operation, and service which has caused the CM-60 module to become by far *the most widely installed cogeneration module in the United States.*

The equipment specifications and schematic are shown on the reverse side.

The TECOGEN CM-60 is supported by programs facilitating easy installation, financing, maintenance and operation. Installations benefit from such aspects as detailed system design support to your engineer, only five accessible, flexible connections to the unit, and low fuel inlet pressure requirements. The TECOGEN CM-60 has a variety of purchase, lease, shared savings and discounted energy programs available to assist in financing. The TECOGEN CM-60 is available with a low cost maintenance agreement covering scheduled maintenance, overhauls and unscheduled problems—you simply turn it to "automatic" and forget it. The equipment design and programs such as these are dedicated to providing you with the best operating cogeneration system available today.

TECOGEN® CM-60 Cogeneration Module
Specifications And Indoor Configuration Schematic


Exhaust gas out
Acoustic enclosure
Microprocessor control system
Gas in
Water out
Water in
Electrical interconnect
Induction generator
3' 10"
3
4
2
1
Heat exchangers
1 Oil Cooler
2 Engine Coolant Heat Exchanger
3 Exhaust Heat Exchanger
4 Water Cooled Exhaust Manifold
Skid
3' 8"
6' 10"
Crusader engine
Vibration isolators

Specifications

Output:	
Electrical	60 kW
Thermal	440,000 Btu/hr Hot Water up to 230°F (18 gpm, 170°F In, 220°F Out are Typical)
Input:	760 SCFH(1) of Low Pressure (4-14"wc) Natural Gas (or propane)
Efficiency:	Electrical — 29.8% (LHV, 905 Btu/SCF) — 26.4% (HHV, 1020 Btu/SCF) Combined — 93.7% (LHV) — 83.1% (HHV)
Dimensions:	82" long × 44" wide × 46" high with enclosure and skid. Fits through a standard 36" doorway without the enclosure and with optional narrow skid.
Weight:	3000 lbs.
Acoustic Level:	70 dBa at 20 ft.
Controls:	Completely automated via microprocessor-based control system, allowing for unattended operation.
Power Generation:	Induction generator with switchgear for parallel operation.

(1) HHV of 1020 Btu/cubic ft.

Specifications subject to change without notice.

TECOGEN INC.
A subsidiary of Thermo Electron Corporation
45 First Avenue
P.O. Box 9046
Waltham, MA 02254-9046
(617) 622-1400

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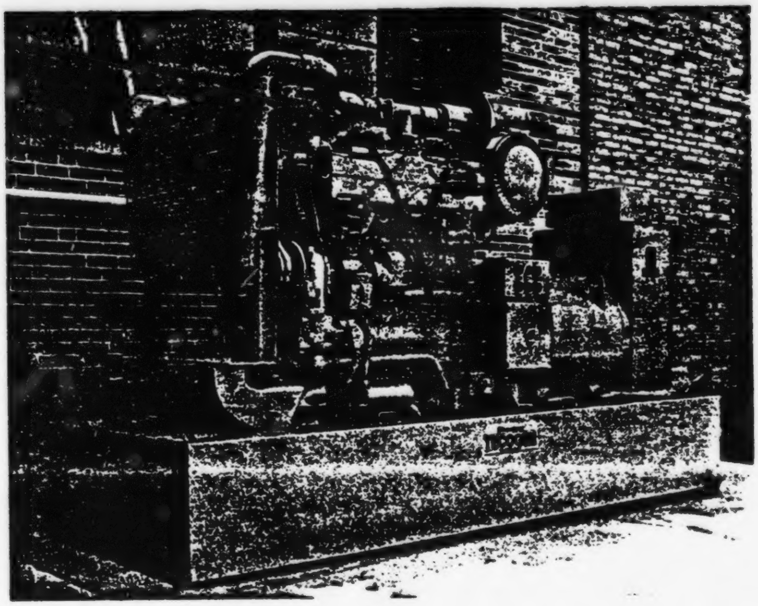
TECOGEN®

CM-200 Cogeneration Module



The TECOGEN CM-200 module provides users with a complete, factory assembled and tested cogeneration system providing 200 kW of electricity and 1.2 MMBtu per hour of thermal output. Multiple modules meet user requirements for up to 1 MW of electric power. The fully integrated package is available for quick delivery (often from stock) and the proven standardized design enables rapid site engineering, permitting, installation and start-up. While the high efficiency assures rapid payback (2 to 4 years) and good return on investment, the resulting facility operating improvements are often even more attractive.

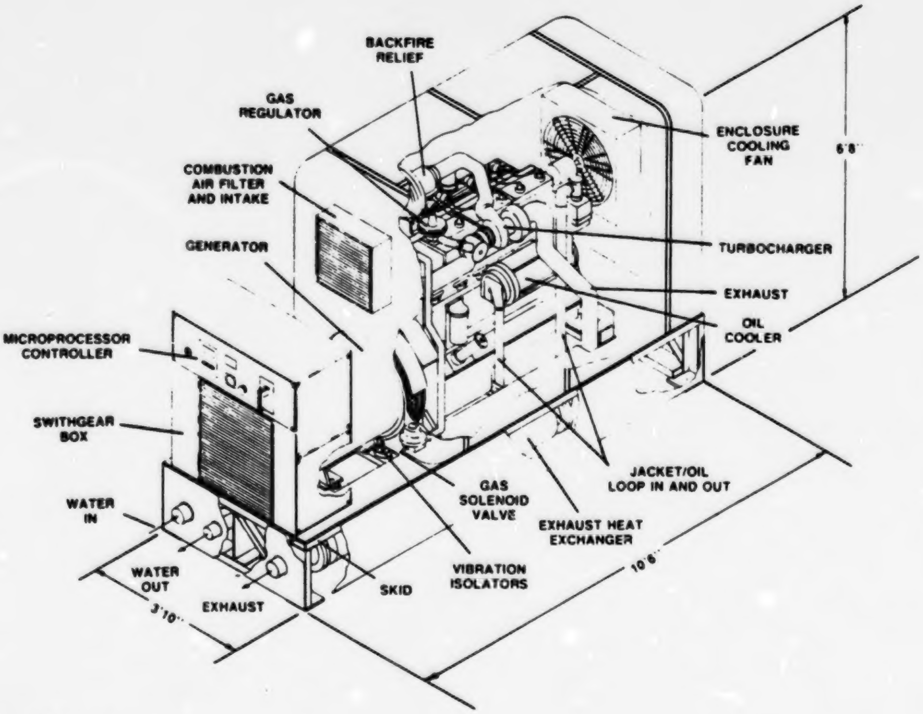
The TECOGEN CM-200 module features:

- Proven reciprocating engine.
- Choice of synchronous or induction generation.
- Efficient heat recovery system for generating hot water, steam or chilled water.
- Electrical switchgear for both parallel and standby operation.
- Microprocessor control system for unattended operation and fast diagnostics.
- Compact, skid-mounted, vibration isolated design with attractive acoustic enclosure for quiet indoor or outdoor (optional) use.

The equipment specifications and schematic are shown on the reverse side.

The TECOGEN CM-200 is supported by features and programs facilitating easy installation, financing, maintenance and operation. Installations benefit from such aspects as detailed system design support to your engineer, only five accessible, flexible connections to the unit and low fuel inlet pressure requirements. The TECOGEN CM-200 has a variety of purchase, lease, shared savings and discounted energy programs available to assist in financing. The TECOGEN CM-200 is available with a maintenance agreement covering scheduled maintenance, overhauls and unscheduled problems—you simply turn it to "automatic" and forget it. The equipment design and programs such as these are dedicated to providing you with the best operating cogeneration system available today.

TECOGEN® CM-200 Cogeneration Module
Specifications And Indoor Configuration Schematic


BACKFIRE RELIEF
GAS REGULATOR
COMBUSTION AIR FILTER AND INTAKE
GENERATOR
MICROPROCESSOR CONTROLLER
SWITHGEAR BOX
WATER IN
WATER OUT
EXHAUST
3'10"
SKID
VIBRATION ISOLATORS
GAS SOLENOID VALVE
EXHAUST HEAT EXCHANGER
JACKET/OIL LOOP IN AND OUT
10'6"
ENCLOSURE COOLING FAN
6'8"
TURBOCHARGER
EXHAUST
OIL COOLER

Specifications

Output:	
Electrical	200 kW
Thermal	1,182,000 Btu/hr Hot Water up to 200°F (or 774,000 Btu/hr Hot Water up to 200°F and 408,000 Btu/hr Steam up to 125 psi)
Input:	2,380 SCFH(1) of Low Pressure (8"-12"wc) Natural Gas (or propane)
Efficiency:	Electrical — 31.7% (LHV) — 28.6% (HHV) Combined — 86.6% (LHV) — 78.1% (HHV)
Dimensions:	10'6" long × 3'10"wide × 6'8" high with enclosure. Fits through a standard 4' doorway without the enclosure.
Weight:	8000 lbs.
Acoustic Level:	75 dBa at 20 ft.
Controls:	Completely automated via microprocessor-based control system, allowing for unattended operation.
Power Generation:	Synchronous generator with switchgear allowing parallel and standby operation (Induction generator option).

(1) HHV of 1020 Btu/cubic ft.

Specifications subject to change without notice.

TECOGEN INC.
A subsidiary of Thermo Electron Corporation
45 First Avenue
P.O. Box 9046
Waltham, MA 02254-9046
(617) 622-1400

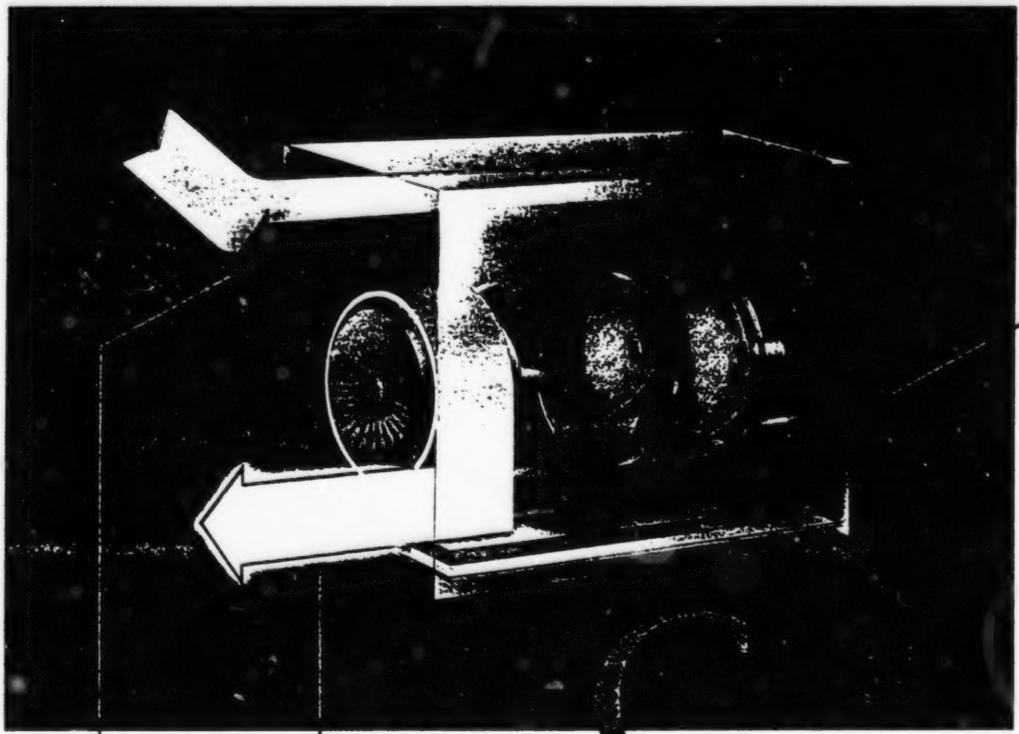
3/88

COGENIC
COGENIC

Now the Power *and the Savings* are Yours

COGENIC
ENERGY SYSTEMS INC

NOW THE POWER IS YOURS
With Cogenic Energy Systems



FUEL SOURCE: Natural gas, diesel oil or propane.

THERMAL ENERGY: Domestic hot water, chilled water and/or process steam.

ELECTRIC ENERGY: "Utility-grade" electricity.

COGENERATION, the use of a single fuel to produce electricity and heat at the same time, has enormous energy saving potential.

Now this highly-efficient technology is also the most cost-effective—thanks to the COGENIC® Module.

Designed specifically to reduce energy costs, the COGENIC Module is a highly reliable, factory-built, pre-tested packaged cogeneration system.

Installed on-site, the COGENIC Module recovers up to 80% of the waste heat produced by the generation of electricity. This heat is converted to hot water, chilled water and/or process steam for use in the facility.

If you presently have an average energy consumption of at least 100 kilowatts per hour of electricity and 500,000 BTUs per hour of thermal energy, there's a COGENIC Module built to power your facility.

COGENIC
M-100
COGENIC
M-100

M-100

YOU SAVE

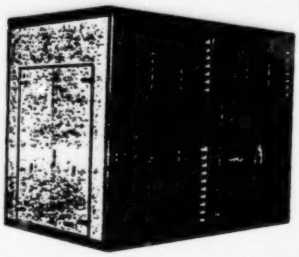
Let's face it. Your decision to cogenerate will depend on the amount of savings you can expect to realize.

LOW COST ENERGY:
Save money by producing electricity, hot water, chilled water or steam for less than the price of electricity alone.

By producing both electric and thermal energy from a single fuel source, the energy costs for your facility can be lowered substantially when you cogenerate. And, because a COGENIC Module can provide most—or all—of the electricity you need, cogenerating provides long-term insurance against escalating utility rates.

LONG-TERM INSURANCE, SHORT-TERM PAYBACK:
Recoup your investment in about three years—Turn your savings into profits.

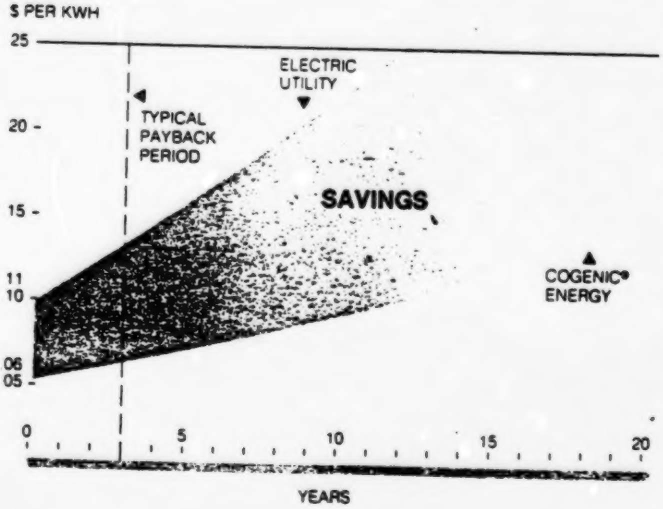
Take the energy dollars you would normally use to pay electric and fuel bills during the next few years and invest in a COGENIC energy system. The rewards are long-term: 20 to 30 years of reliable, cost-contained energy for your facility.



M-145

AFFORDABLE FINANCING:
COGENIC has flexible financing packages to meet any budget.

COGENIC Modules are available on a variety of financial plans including "shared-savings," tax lease, lease purchase, utility rate discounting and outright purchase. In most cases, a financial package can be tailored to provide energy savings which are greater than the average monthly payments.



WE SERVICE

At Cogenic Energy Systems, we believe that our customers simply want a trouble-free way to save energy dollars.

Because they are virtually "turn-key," COGENIC's packaged cogeneration systems are completely trouble-free. Designed, manufactured, installed, operated and maintained by us, COGENIC Modules are among the most reliable energy systems available today.

SIMPLE INSTALLATION:
COGENIC Modules can be installed on-site in just hours.

A modular COGENIC system can be installed almost anywhere—outdoors, indoors, on a rooftop, or in a basement or boiler room—in as little as one half day.

COGENIC Modules undergo pre-engineering packaging and pre-testing at our factory to mee the individual specifications of your facility. After your site has been prepared with the wiring, the piping and a pad to accommodat the unit, the skid-mounted, vibration-isolate module can be connected in a matter of hours—causing little or no disruption to the operation of your facility.

ON-LINE MONITORING:
On-line monitoring provides surveillance, testing, trouble-shooting and cost-control of each system.

The newly-developed COGENIC data center allows us to maintain maximum control over your system via modem. Using COGENIC-developed software to monitor critical mechanical points and report on the operation of the system, your COGENIC energy system will be maintained t run both reliably *and* cost-effectively.

TROUBLE-FREE OPERATION:
All Modules are maintained and serviced by COGENIC.

COGENIC uses only utility-grade prime movers and compatibly-matched components. Designed for extremely long life and ease of maintenance, a COGENIC Module is fully expected to operate continuously with a minimum of preventive maintenance and periodic minor and major overhauls.

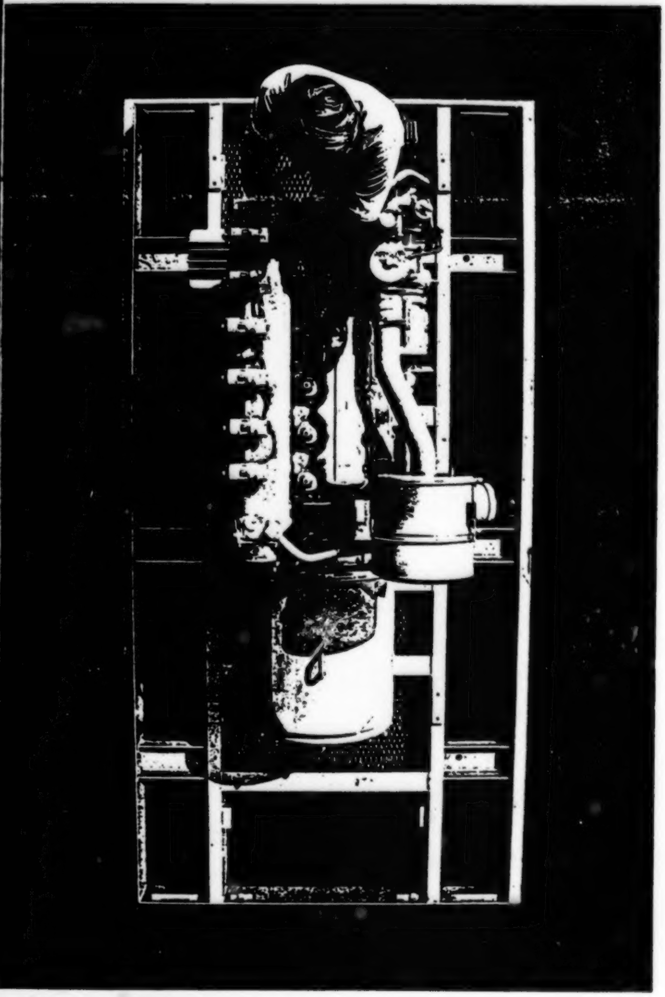
COGENIC's dedication to quality extends from our initial survey of your facility all the way through to the complete maintenance service provided by COGENIC. These service cover everything from the on-line monitoring of day-to-day operations to the parts and labor needed to keep your COGENIC energy system in top operating condition.

YOU CAN DEPEND ON COGENIC

Cogenic Energy Systems, Inc., widely-recognized as a leader in the cogeneration industry, developed the concept of the packaged cogeneration system in the late 1970s.

Our key staff members have decades of experience in designing and operating cogeneration systems that work…and are still working after many tens of thousands of hours of operation.

As more varied applications for cogeneration have become evident, COGENIC has continued to guide the industry in the development of sophisticated, state-of-the-art energy systems to meet the needs of today's cogenerators.



M-450

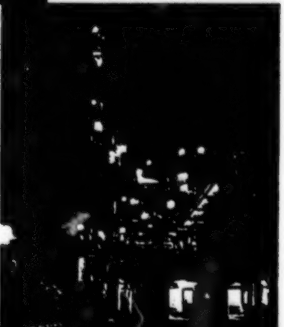
COGENIC MODULES

are available to meet the energy needs of a wide range of applications.

Cogenic Energy Systems, Inc. pioneered modular, packaged cogeneration systems. Today, COGENIC has delivered packaged cogeneration systems with *more* total capacity and *more* logged operating hours than all other manufacturers combined in industries such as these:

LODGING

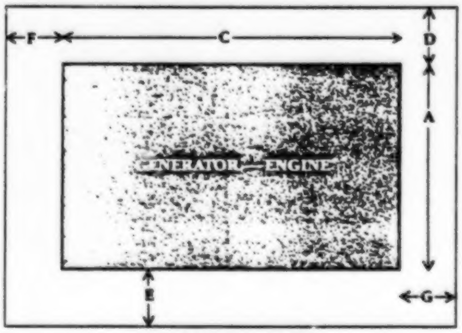
HEALTH-CARE



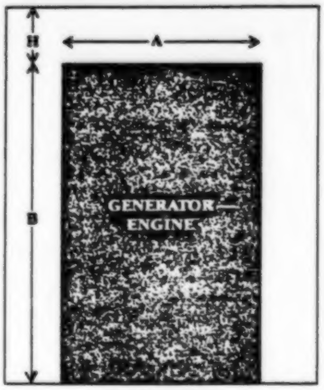
INDUSTRIAL

INSTITUTIONAL

SPECIFICATIONS



OVERHEAD VIEW



END VIEW

MODEL	kW OUTPUT[5]	DIMENSIONS (Inches) A	B	C	D	E	F	G	H	FUEL INPUT[1] MBH	HEAT OUTPUT MBH	WEIGHT (approx) x 1,000 lbs.
100 Series (1800 RPM)												
M-100 GWI	**100**	**72**	**103**	**144**	**36**	**36**	**108**	**36**	**48**	**1200**	**630 HW**	**11**
M-100 GWI*	100	36	84	110	36	36	108	36	12	1200	630 HW	5.3
M 100 GCI*	**100**	**96**	**84**	**144**	**36**	**60**	**36**	**36**	**12**	**1200**	**630 HW or 36 tons AC**	**15.2**
M-120 DWI	120	72	103	144	36	36	108	36	48	1330	680 HW	11
M-145 GWI	**145**	**90**	**116**	**144**	**72**	**36**	**96**	**36**	**48**	**1670**	**830 HW**	**13**
M-145 GWI*	145	48	76	114	36	36	96	36	12	1670	830 HW	6.7
M-145 GCI*	**145**	**96**	**84**	**144**	**36**	**60**	**36**	**36**	**12**	**1670**	**810 HW or 52 tons AC**	**16.5**
300 Series (1200 RPM)*												
M-350 GWS	**350**	**94**	**82**	**191**	**36**	**36**	**105**	**36**	**14**	**4000**	**2000**	**26.5**
M-350 GSS	350	94	115	191	36	36	105	36	12	4000	2000[6]	28.5
500 Series[2] (1200 RPM)*												
Single fuel (gas or diesel)										Gas (Diesel)	Gas (Diesel)	
M-500 WS	**500[7]**	**94**	**82**	**191**	**36**	**36**	**105**	**36**	**14**	**6000 (5500)**	**3000 (2700)**	**26.5**
M-500 SS	500[7]	94	115	191	36	36	105	36	13	6000 (5500)	3000 (2500)[6]	28.5
M-500 HPS	**500[7]**	**118**	**115**	**191**	**36**	**36**	**105**	**36**	**14**	**6000 (5500)**	**3000 (2500)[3,6]**	**30.5**
700 Series (1200 RPM)*												
Single fuel (gas or diesel)										Gas (Diesel)	Gas (Diesel)	
M-650 WS	**650[7]**	**94**	**82**	**250**	**36**	**36**	**105**	**36**	**14**	**8000 (7300)**	**4000 (3600)**	**35.2**
M-650 SS	650[7]	94	115	250	36	36	105	36	12	8000 (7300)	4000 (3400)[6]	37.2
M-650 HPS	**650[7]**	**118**	**115**	**250**	**36**	**36**	**105**	**36**	**14**	**8000 (7300)**	**4000 (3400)[3,6]**	**39.2**
700 Series (900 RPM)*												
Dual Fuel (gas and diesel)												
M-665 DF (WS, SS, HPS)	665	Several package arrangements are available — Call Factory								6780[4]	2400[6]	46
1000 Series (900 RPM)*												
Dual Fuel (gas and diesel)												
M-1124 DF (WS, SS, HPS)	**1125**	**Several package arrangements are available — Call Factory**								**12088[4]**	**3900[6]**	**74**

**without enclosure.*

---

[1] Gas consumption is higher heat value
[2] 500 kW with 90°F aftercooler water, 450 kW with 130°F aftercooler water
[3] Only 30% of heat in the form of high pressure steam
[4] 90% natural gas; 10% pilot oil or 100% diesel
[5] Generator is rated at .8 power factor
[6] 6% of total heat recoverable is in the form of 170°F HW
[7] Ratings can be increased by up to 40% on diesel models—Call Factory

STANDARD FEATURES

- ☐ Structural steel base
- ☐ Automatic lube oil makeup system
- ☐ Engine starting batteries and charger
- ☐ Crank case emission absorber system
- ☐ Vibration isolators
- ☐ Flexible fuel, hot water and exhaust lines
- ☐ Electrical control cabinet, main circuit breakers, frequency, voltage and kilowatt meters
- ☐ Engine and exhaust heat recovery system
- ☐ Engine power level control
- ☐ Built to ASME and NEMA standards
- ☐ Excess heat control
- ☐ Automatic safety shutdown
- ☐ Unattended startup
- ☐ Engine gauge panel
- ☐ Integral hot water heat exchanger
- ☐ Excess heat exchanger
- ☐ Sound attenuated all-weather steel enclosure

OPTIONAL EQUIPMENT

- ☐ Btu thermal output meter
- ☐ Kilowatt hour meter
- ☐ Remote monitoring and alarm system
- ☐ Different voltages available
- ☐ Induction or synchronous generators

Note: COGENIC systems are designed to "utility grade" standards for either induction or synchronous applications. This means that the system can accommodate the base load electric (and thermal) consumption, as well as peak shaving or emergency standby operation.

COGENIC® MODULE DESIGNATIONS

M — 100 — G — W — I

UNIT TYPE
M — Modular

KW RATING

FUEL TYPE
G — Natural Gas
D — Diesel
DF — Dual Fuel
(diesel and natural gas)

RECOVERY SYSTEM
W — Hot Water
S — Steam
HP — High Pressure
C — Chilled Water

GENERATOR TYPE
I — Induction
S — Synchronous

COGENIC MAKES COGENERATION SIMPLE

COGENIC® provides:

- ☐ Complete initial feasibility studies.
- ☐ Factory engineering and on-site installation.
- ☐ Total financing flexibility including direct purchase, lease agreements and shared savings plans.
- ☐ Full-service maintenance nationwide.
- ☐ 24-hour computer monitoring.
- ☐ Full EMS compatibility.
- ☐ Dependable *American-made* energy systems, built to provide years of cost-saving service!

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All YOU have to do is decide to cogenerate. COGENIC makes it simple.

COGENIC
ENERGY SYSTEMS INC

CORPORATE HEADQUARTERS
127 EAST 64TH STREET
NEW YORK, NEW YORK 10021

Call Toll Free for More Information Today!
1-800-238-8880

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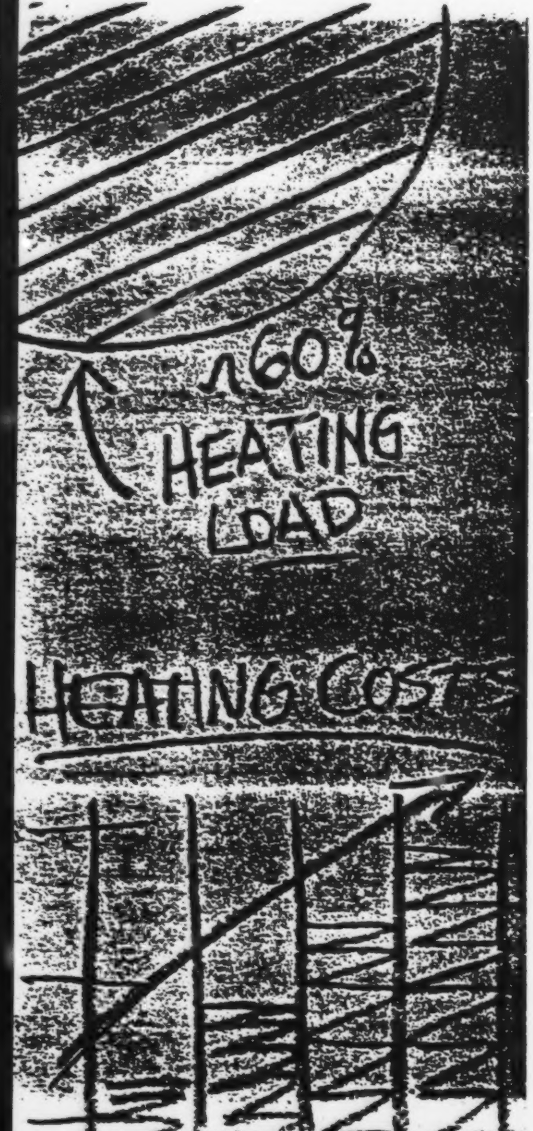
WAUKESHA COGENERATION MODULES

Waukesha DRESSER



Waukesha Coger

Emphasis on Energy Savings, Fuel Effic

Utilizing the heat by-product of a reciprocating engine through cogeneration has become one of the most cost-effective means of meeting ever increasing energy costs.

Cogeneration has long been viable for large plants and institutions. Now the Waukesha Power Systems, Waukesha Engine Division, Dresser Industries, Inc. offers pre-engineered modular generating systems, which meet cogeneration application requirements in the 24 to 375 KW range.

Waukesha Offers You Single-Source Responsibility for the Complete System.

All Waukesha Cogeneration Modules are fully factory tested prior to shipment, and each one carries the Waukesha warranty. These modular units are complete and ready to install. Waukesha Cogeneration Modules combine the following components in a compact package: engine, generator, heat recovery silencer, heat exchanger, water pump and a Waukesha Engomatic* Control System. *All* components are factory engineered with latest technology; built to industry standards; mounted on a structural steel skid . . . *allowing for simplified installation and on-line ease of startup and operation.* You receive a cogeneratio system with each component designed to provide maximum efficiency and long life with low operating costs. The entire system combines the latest designs, highest quality materials and workmanship and full factory testing. A worldwide network of distributors is available to supply you with parts and service.

Check These Benefits.

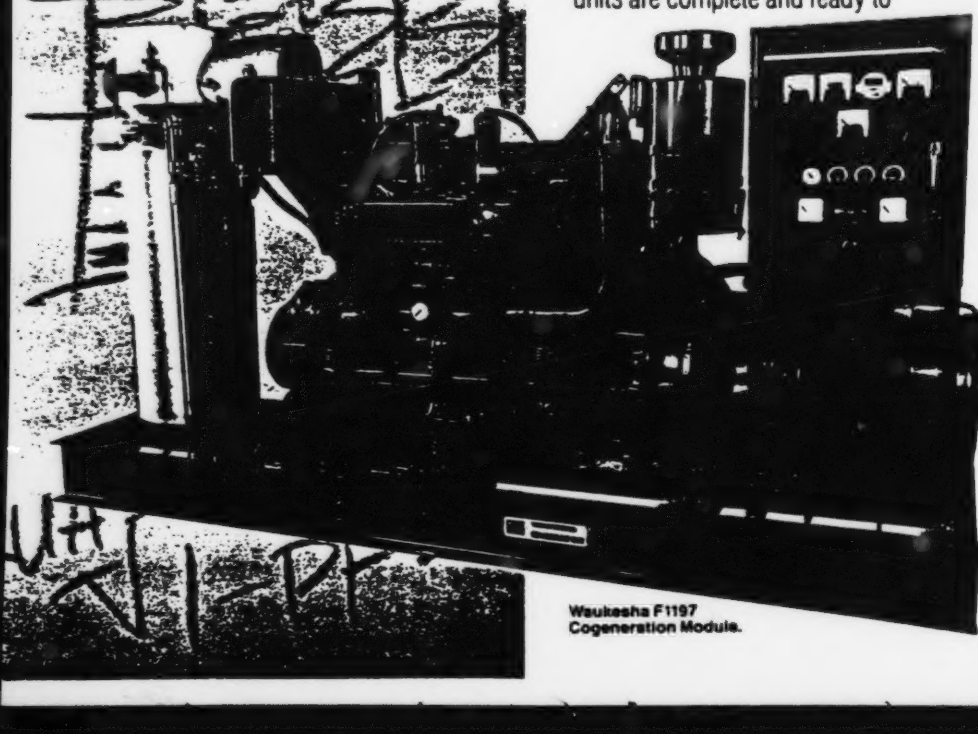
- Waukesha Quality
- Single Source Responsibility
- Effective Control of Energy Costs
- Broad Range of Output Capabilities
- Attractive Payback

When you specify a Waukesha Cogeneration Module you get *Single Source Responsibility.*

Waukesha Offers You One of the Most Effective Means of Controlling Your Energy Costs.

Cogeneration saves you money by saving fuel. By using a Waukesha Cogeneration Module to both generate electricity and provide heat, you virtually eliminate the equivalent amount of fuel you previously would have used just to provide heat.

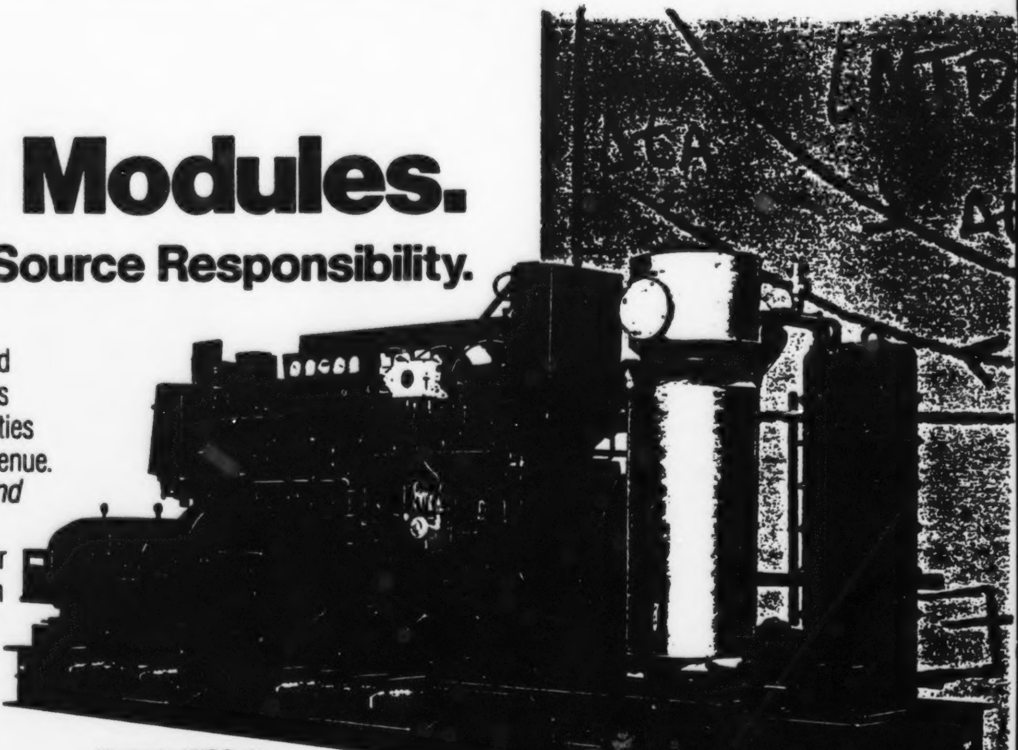
By generating your own electric power efficiently for either base loading or peak shaving, you also afford yourself the possibility of creating



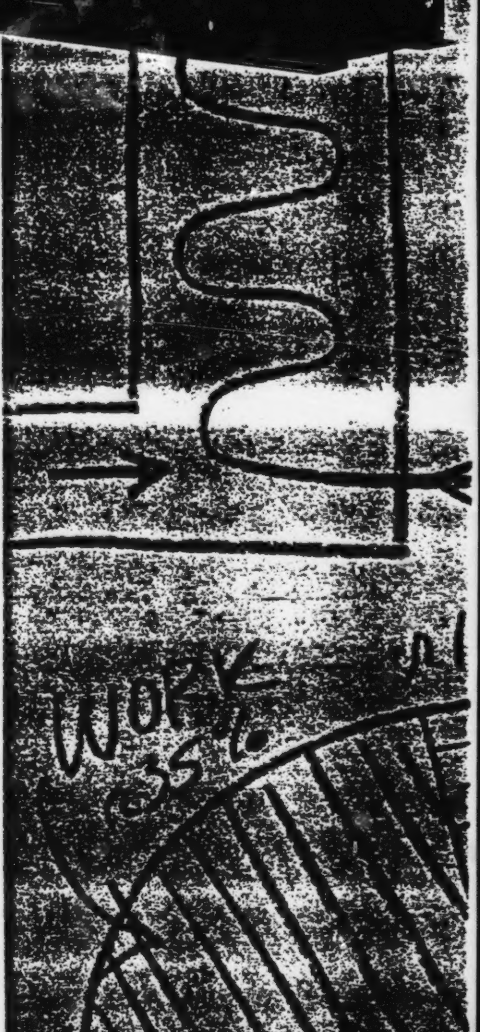
Waukesha F1197 Cogeneration Module.

eration Modules.

ency and Single Source Responsibility.



Waukesha VHP Series
Large Cogeneration Module



excess electricity which you could then sell to your local utility. Sales of excess electricity to public utilities provides a potential source of revenue.

Fuel savings, reduced demand charges, and *potential excess electricity sales* when using your Waukesha Modular Cogeneration System, *all result in substantial dollar savings to you.*

Waukesha Offers You a Broad Range of Output Capacities to Meet Your Needs.

Waukesha Power Systems presently offers pre-engineered Cogeneration Modules providing output capacities ranging from 24 to 375 KW.

The factory assembled modular systems can be used as a single unit or in multiples for increased power output. They can be ordered with induction generators that parallel with utility grids, or with synchronous generators that can operate alone or in parallel with the utility.

Utilizing synchronous generation, the Waukesha modular unit can double as an emergency generator in event of a utility blackout.

Larger custom engineered packages are available to 1.5 megawatts.

Waukesha Offers You a Cogeneration Module Suitable for a Variety of Applications.

There are many applications that can benefit from a Waukesha Modular Cogeneration System: *Light Industry. Hotels and Motels. Hospitals. Nursing Homes. Laundries. Apartment Complexes. Colleges and Universities. Large Swimming Pools. Food Processors. Beverage Processors. Restaurants.*

Waukesha Offers You Attractive Payback Periods.

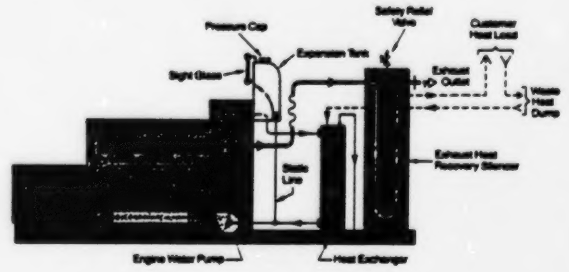
If you are currently using natural gas to provide heat and purchasing electricity from your utility, you could be saving money with a Waukesha Modular Cogeneration System. Waukesha Power Systems has the capability of providing you with a cogeneration feasibility analysis which will estimate savings and present an investment analysis of your installation.

Contact your nearest Waukesha Distributor or Sales Office for a free feasibility analysis to determine the payback of your project. *Find out how you can produce electricity and provide heat for the price of electricity alone.*

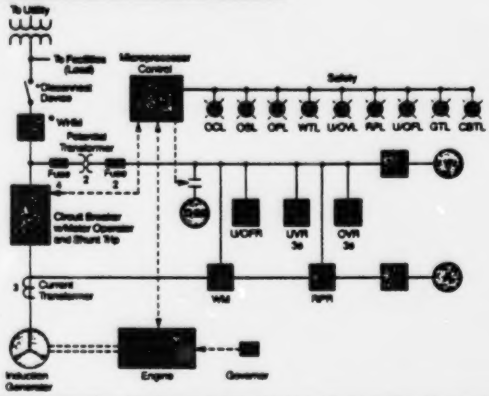
WAUKESHA COGENERATION MODULES

WAUKESHA ENGINE MODEL	ELECTRICAL ENERGY RPM	ELECTRICAL ENERGY KW	TYPICAL RECOVERABLE THERMAL BTU's/hr
60-Hz Gas			
L3800G	1200	375	2,112,000
H2500G	1200	250	1,430,000
F2000G	1200	175	986,000
F1197G	1200	115	709,000
F817G	1200	75	443,000
VRG330S	1800	65	360,000
VRG330	1800	45	303,000
VRG220	1800	30	193,000
60 Hz DIESEL			
VS900DSI	1800	280	991,000
VS900DS	1800	255	931,000
VS700DSI	1800	215	818,000
VS700DS	1800	205	782,000
VS600DS	1800	165	548,000
VRD330S	1800	65	337,000
VRD330	1800	50	235,000
VRD220S	1800	40	217,000
VRD220	1800	30	156,000
50 Hz GAS			
L3800G	1000	325	1,749,000
H2500G	1000	225	1,228,000
F2000G	1000	150	823,000
F1197G	1500	135	886,000
F817G	1500	90	552,000
VRG330S	1500	55	300,000
VRG330	1500	38	279,000
VRG220	1500	24	176,000
50 Hz DIESEL			
VS900DSI	1500	250	839,000
VS900DS	1500	225	821,000
VS700DSI	1500	190	708,000
VS700DS	1500	175	674,000
VS600DS	1500	145	496,000
VRD330S	1500	54	284,000
VRD330	1500	40	186,000
VRD220S	1500	32	168,000
VRD220	1500	25	151,000

Flow Diagram


Pressure Cap
Safety Relief Valve
Customer Heat Load
Expansion Tank
Sight Glass
Exhaust Outlet
Waste Heat Dump
Static Line
Exhaust Heat Recovery Silencer
Engine Water Pump
Heat Exchanger

Control Schematic


To Utility
To Facilities (Load)
Microprocessor Control
Safety
Disconnect Device
Watt
Potential Transformer
OCL
OSL
OPL
WTL
U/OVL
RPL
U/OFL
GTL
CBTL
Fuse 4
2
Fuse 2
Circuit Breaker w/Motor Operator and Shunt Trip
U/OFR
UVR 3ø
OVR 3ø
3
Current Transformer
WM
RPR
Induction Generator
Engine
Governor

For further information, contact your Waukesha Distributor, or Factory Sales Office.

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(303) 779-5675

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(713) 893-4170

Waukesha DRESSER

Waukesha Engine Division
Dresser Industries, Inc.
1000 West St. Paul Avenue
Waukesha, WI 53188

Bulletin #1291 2/87

Litho in U.S.A.

CULLEN GAS TURBINE POWER SYSTEMS

Cogeneration

The gas turbine is well suited for in-plant power generation systems that provide low or high pressure steam, hot water or process heat additional to the electrical energy derived from burning liquid or gaseous fuels.

We are entering a period in our economy when utilities are looking with favor on in-plant generation systems that can feed the utility grid with their excess electrical energy. There are favorable dollars-and-cents reasons to develop a cogeneration system if you have a process that can use the by-products of a gas turbine generator — heat in the form of hot air, hot water or steam.

Cullen has the experience and know-how to work with you in the design of these systems, and to take full responsibility for providing all system components. This can include fuel treating systems, fuel gas compressors if required, steam generators, economizers, steam turbines, bypass and isolation valves, etc.

Developing a cogeneration system that operates at the highest possible efficiency requires a careful selection and matching of components. It also requires a high level of communication between the supplier and end user to assure that the trade-offs made in any system design are to the benefit of the user.

When you think of the advantages of cogeneration, think of the advantages of working with Cullen. With the wide range of turbines available, we offer the flexibility to meet your exacting requirements.

The Cheng Cycle

The Cheng Cycle Series 7 — Cogen System is a patented product developed by International Power Technology (IPT) of Palo Alto, California. Through an agreement with IPT, Cullen is authorized to market the product in conjunction with IPT.

This complete cogeneration package produces:

- 3.5 to 6.0 Mw of power at 27 – 39% generating efficiency;
- 0 to 45 million Btu per hour of process thermal energy.

Key advantages are: An outstanding ability to track varying loads economically; high electrical capacity and generating efficiency; mechanical simplicity and reliability; superior NOx control; sophisticated controls to maximize economic returns.

This system can be applied to installations with a wide range of total energy requirements and is particularly attractive for installations with fluctuating thermal loads. Because of Cheng Cycle's operating flexibility, periods of low thermal load requirements create opportunities to produce more electricity more efficiently.

The Cheng Cycle is an advanced heat engine cycle which combines and optimizes the Brayton (gas turbine) and Rankine (steam turbine) cycles. These two cycles are combined using a single Allison (Division of General Motors) 501 gas turbine which is modified for Cheng Cycle operation.

Exhaust heat from the gas turbine is used to produce steam in a matched heat recovery steam generator (HRSG). Steam produced in the HRSG can be used either for injection into the turbine or for process. Steam is injected into the turbine when process thermal loads are low or when it is economically desirable to maximize power output.

Major components of the cogeneration system are: Allison 501 gas turbine generating set designed for Cheng Cycle operation; matched heat recovery steam generator; real time computer-based cycle and economic controls.

The Cheng Cycle 501-KH is backed by Allison's full warranty and service support.

The heat recovery steam generator (HRSG) is an integral part of the system and requires careful matching of its characteristics with those of the 501-KH turbine. Provisions for burning additional fuel in the HRSG (secondary combustion) are included since this significantly increases system operating flexibility.

The system includes a sophisticated computer based control system which is designed to ensure that the cogeneration plant operates in the most reliable and economic manner. The control system operates on two levels:

1) A functional level controls cycle parameters to maximize efficiency and ensure reliability by governing the physical parameters of the system (i.e. fuel flow, steam flow, etc.). It implements the operating strategy chosen by the supervisory level, and ensures that process requirements are met at all times.

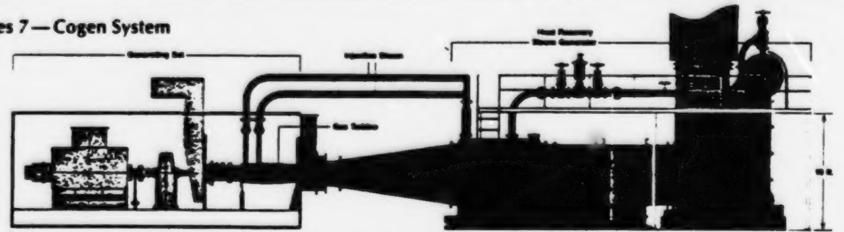
2) A supervisory level which optimizes system economics on a real time basis. In addition, the supervisory level performs many record-keeping tasks relating to system performance (both economic and technical) and regulatory compliance.

The control system is also designed by International Power Technology. Reliability is ensured through the use of proven components and backup systems.

Dimensions: The complete system including balance of plant, requires a space of approximately 45 x 100 feet. In situations where space is a limiting factor, the system can be configured to meet specific needs.

Pollution Control: NOx control is an inherent feature of Cheng Cycle operation. Steam injection is capable of greater NOx reduction than water injection, the most commonly used control technology.

Cheng Cycle Series 7 — Cogen System



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APPENDIX C
DETAILED FUEL AND ELECTRICAL COSTS

CANADIAN NATURAL GAS PRICES

Under natural gas deregulation, the price of natural gas in the Toronto market would reflect the demand for natural gas and the price of competing fuels. Wholesale prices in Toronto would vary depending on the end use market for the gas. The price discounts which the distribution utilities with their long term contracts have so far been able to negotiate are less than those negotiated by large industrial customers who have access to other fuels. Natural gas sold by TranCanada PipeLines to the distribution utilities is referred to as system gas.

Residential and Commercial consumers are expected to receive a discount of 20¢/GJ beginning November 1, 1986 and it is possible that the price to them would stay flat for at least two years. Industrial customers, on the other hand, have been successful in negotiating discounts in the $1.00 range. Prices in the near term could reflect the price of heavy fuel oil, the major competitor for natural gas in industrial markets. In order to allow natural gas to remain competitive, gas transmission costs from the Alberta border to Toronto could remain at 1986 levels with gas producers absorbing any cost increases. While pipeline cost increases are expected to be modest over the 1985-2000 period, there would probably be a greater pass through of full pipeline costs to consumers beginning in 1989 as markets tighten.

Low Case: The ratio of the wholesale natural gas price to the crude oil price in Toronto on an energy equivalent basis fluctuates between 115 and 120 per cent over the forecast period. This relationship will probably hold because a major part of the cost of gas delivered to end use markets is the relatively rigid transmission cost. Industrial users will be able to obtain gas at a significant discount from the wholesale price in order for gas producers to retain markets.

Gas transmission cost increases from the Alberta border to Chicago and Toronto will likely be constrained in order to allow gas to remain competitive with oil in end use markets. Cost increases would be held below the rate of inflation as pipeline returns, costs and capacity additions could be squeezed.

Mid Case: As oil prices begin to strengthen the ratio of gas to oil prices in Toronto could decline from 100 per cent in 1987 to 90 per cent by 1990, 85 per cent by 1995 and 80 per cent by the end of the century. The ratio declines as gas regains market share particularly in the industrial market. The decline in the ratio is slowed by the disappearance of the U.S. gas bubble in the late 1980s and early 1990s.

Natural gas transmission costs are assumed to increase at a rate below the rate of inflation. This allows an increase in the competitive position of natural gas in end use markets.

High Case: This scenario allows for an escalation in oil prices in the 1990s which spills over into natural gas markets. However, gas supplies would likely be large enough to keep the price from rising as rapidly as the oil price.

The energy equivalent ratio of gas to oil in Toronto could therefore fall to 85 per cent in 1990, 75 per cent in 1995 and 70 per cent by the year 2000.

Table 4

Price at the Alberta Border for System Gas
(Canadian $/GJ)

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	2.87	2.80	2.87	2.80	2.87	2.80
1986	2.76	2.76	2.76	2.76	2.76	2.76
1987	2.51	2.60	2.54	2.60	2.53	2.60
1988	2.45	2.60	2.47	2.60	2.46	2.60
1989	1.60	1.75	2.31	2.52	2.35	2.57
1990	1.72	1.95	2.20	2.49	2.93	3.33
1995	1.92	2.62	2.88	3.99	3.41	4.79
2000	1.86	3.09	2.89	4.94	3.36	5.91

Table 5

Toronto Wholesale Price for System Gas
(Canadian $/GJ)

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	3.87	3.79	3.87	3.79	3.87	3.79
1986	3.75	3.75	3.75	3.75	3.75	3.75
1987	3.47	3.59	3.50	3.59	3.50	3.59
1988	3.39	3.59	3.40	3.59	3.39	3.59
1989	2.51	2.75	3.23	3.52	3.44	3.76
1990	2.62	2.97	3.10	3.51	4.02	4.57
1995	2.86	3.75	3.68	5.11	4.48	6.30
2000	2.60	4.31	3.60	6.16	4.40	7.74

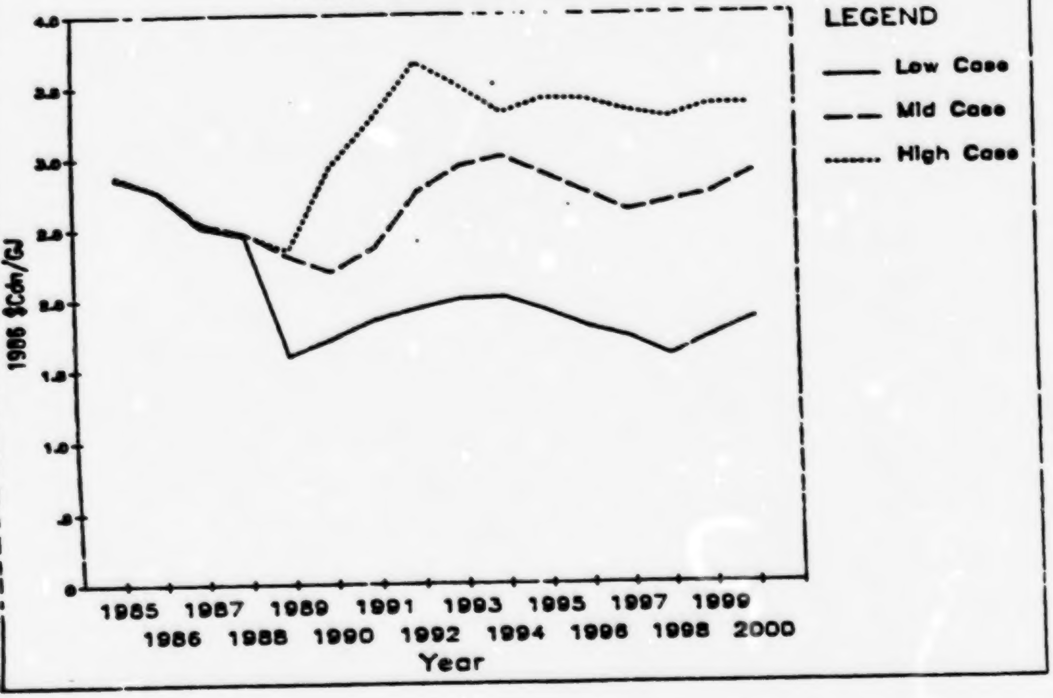


Figure 4
Alberta Border Price

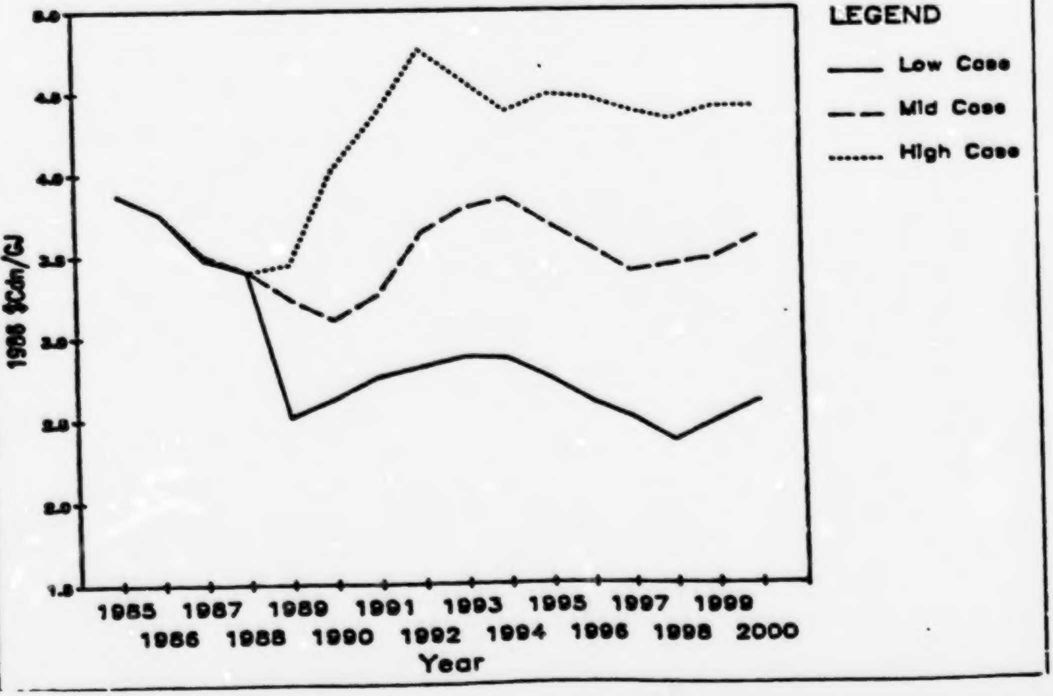


Figure 5
Toronto Wholesale Price

RETAIL PRICES

Natural Gas Prices in Toronto

Residential and small commercial customers will likely receive a 20¢/GJ price decline beginning November 1, 1986. The resulting price level is assumed to hold for two years. Industrial natural gas users have been able to negotiate large discounts, price declines of about $1 per Mcf have been negotiated.

Low Case: In 1987, there is assumed to be a significant shift in distributors' margins from industrial customers to residential customers. Subsequently, residential and commercial distributors' margins could increase at the rate of inflation while industrial distributor margin increases could be held to one per cent a year. Industrial customers would be able to purchase natural gas at a price competitive with fuel oil. In order to meet this price costs would likely be transferred to the captive residential and commercial markets.

Mid Case: Distributor margins for the residential and commercial sectors could increase at the rate of inflation over the 1986 to 2000 period. Industrial customers would be able to obtain gas at a price equivalent to the Toronto Wholesale Price.

High Case: Distributor margins for the residential and commercial sectors could increase at the rate of inflation over the 1986 to 2000 period. Industrial customers would be able to obtain gas at a price slightly above the Toronto Wholesale Price after 1990.

Table 6

Residential Natural Gas Price in Toronto
($/GJ)

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	5.91	5.78	5.91	5.78	5.91	5.78
1986	5.75	5.75	5.75	5.75	5.75	5.75
1987	5.42	5.60	5.46	5.60	5.45	5.60
1988	5.28	5.60	5.31	5.60	5.29	5.60
1989	4.75	5.20	5.27	5.74	5.47	5.98
1990	4.87	5.52	5.13	5.81	6.04	6.87
1995	5.03	6.85	5.71	7.92	6.49	9.12
2000	4.89	8.10	5.60	9.59	6.35	11.17

Table 7

Commercial Natural Gas Price in Toronto ($/GJ)

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	4.70	4.61	4.72	4.61	4.72	4.61
1986	4.72	4.72	4.72	4.72	4.76	4.76
1987	4.41	4.56	4.45	4.56	4.44	4.56
1988	4.33	4.59	4.35	4.59	4.34	4.59
1989	3.45	3.78	4.17	4.54	4.38	4.79
1990	3.56	4.03	4.04	4.57	4.95	5.63
1995	3.70	5.03	4.62	6.40	5.41	7.60
2000	3.56	5.89	4.53	7.75	5.30	9.33

Table 8

Industrial Natural Gas Price in Toronto ($/GJ)

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	4.29	4.19	4.29	4.19	4.29	4.19
1986	4.10	4.10	4.10	4.10	4.10	4.10
1987	3.07	3.17	3.09	3.17	3.09	3.17
1988	2.05	2.17	3.01	3.17	3.47	3.67
1989	2.15	2.35	3.12	3.40	3.81	4.17
1990	2.26	2.56	3.14	3.56	4.36	4.96
1995	2.35	3.19	3.69	5.11	4.82	6.78
2000	2.18	3.62	3.60	6.16	4.73	8.32

[illegible] 3%

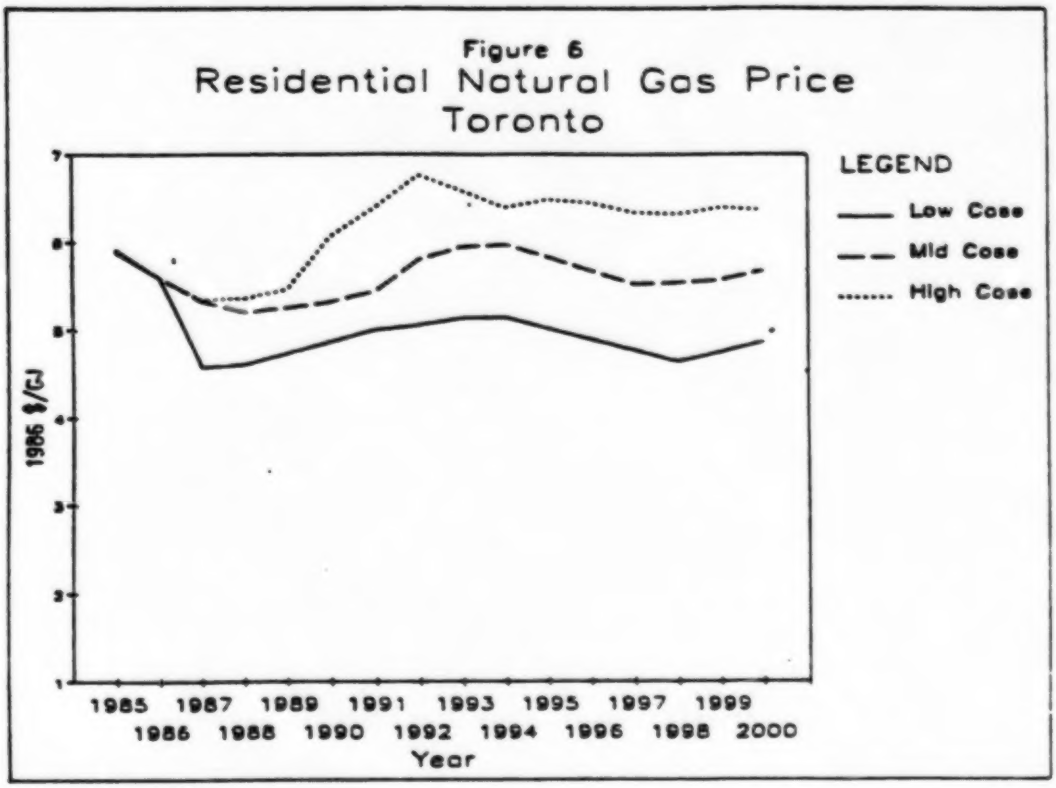


Figure 6
Residential Natural Gas Price
Toronto

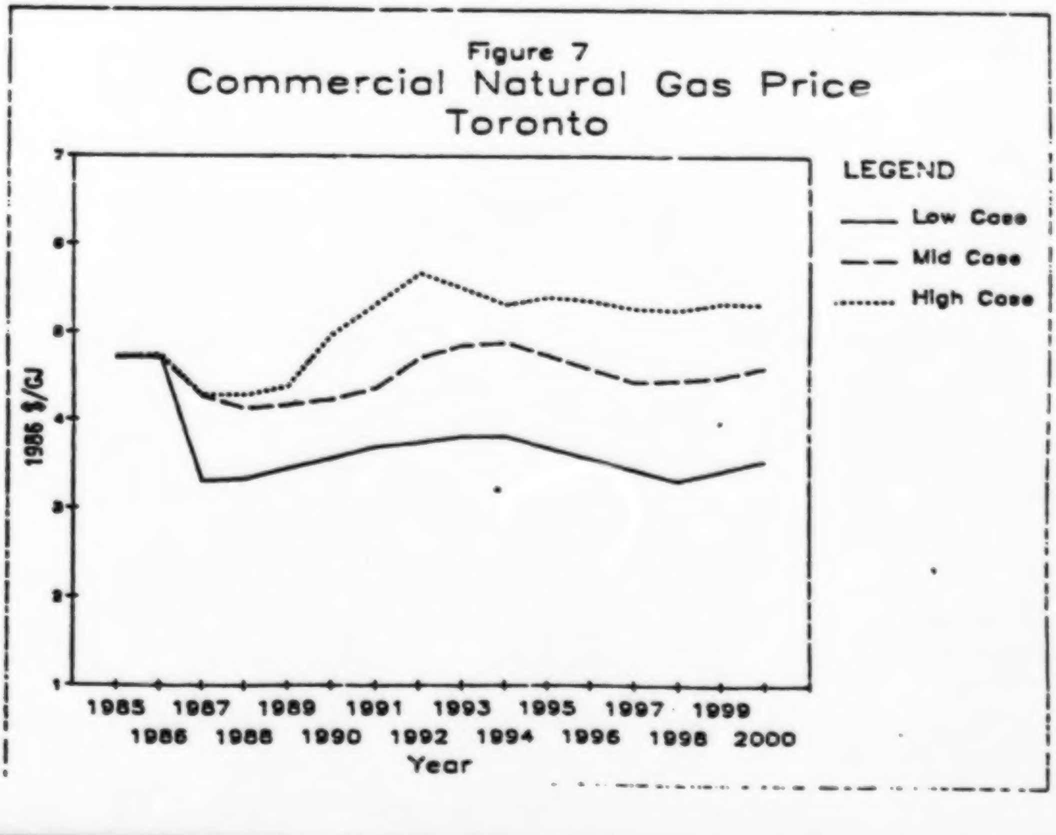


Figure 7
Commercial Natural Gas Price
Toronto

ELECTRICITY PRICES IN TORONTO

Retail Electricity prices to customers of municipalities are made up of two major components:

- The Bulk Electricity Rate charged to municipalities by Ontario Hydro.
- The distribution costs of municipal utilities. These costs are assumed to increase at the rate of inflation in all three cases.

Low Case: Electricity prices could rise 2 per cent per annum above the rate of inflation in the 1986-90 period due to a combination of low inflation, low export sales (low oil prices reduce the price and volume of sales to the U.S.), and the coming on line of generation and transmission facilities the cost of which must begin to be recovered from rates. Between 1990 and 1995 electricity prices could decline one per cent a year in real terms as capacity additions are smaller and nuclear generation becomes a larger component of total generation displacing higher cost coal. After 1995 rates could increase at one per cent per year in real terms as more coal generation is required to meet demand, the costs of acid gas emission regulations must be met and some new generation capacity is required.

Electricity prices in 2000 would be slightly higher in real terms than in 1986.

Mid Case: Electricity prices could rise 1.7 per cent per annum in real terms over the 1986-90 period as inflation is slightly higher and export sales somewhat higher than in the low case and capacity additions are the same. Between 1990 and 1998 prices could fall 1.0 per cent a year in real terms as lower average generation costs due to the higher nuclear share of generation and the low level of capacity additions is offset somewhat by increasing coal generation requirements in the latter part of the period and the cost of acid gas emission regulations. After 1998 there could be some real price increase as capacity additions are needed to meet demand.

- Electricity prices would be slightly lower in real terms in 2000 than in 1986.

High Case: Between 1986 and 1990 electricity prices could increase 1.3 per cent a year in real terms. After 1990 electricity prices could decline 1.5 per cent per annum in real terms as lower economic growth than in the other two cases and lower resulting electricity demand growth could reduce the need to add new capacity in the latter half of the 1990s.

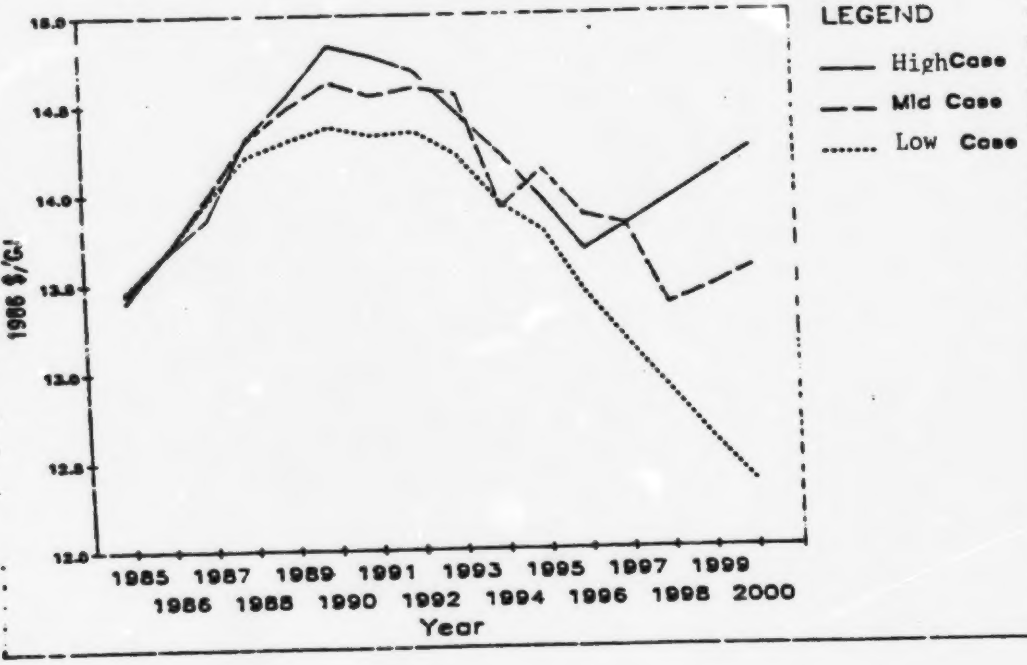
Electricity prices would be 10 per cent lower in real terms in 2000 than in 1986.

Table 12

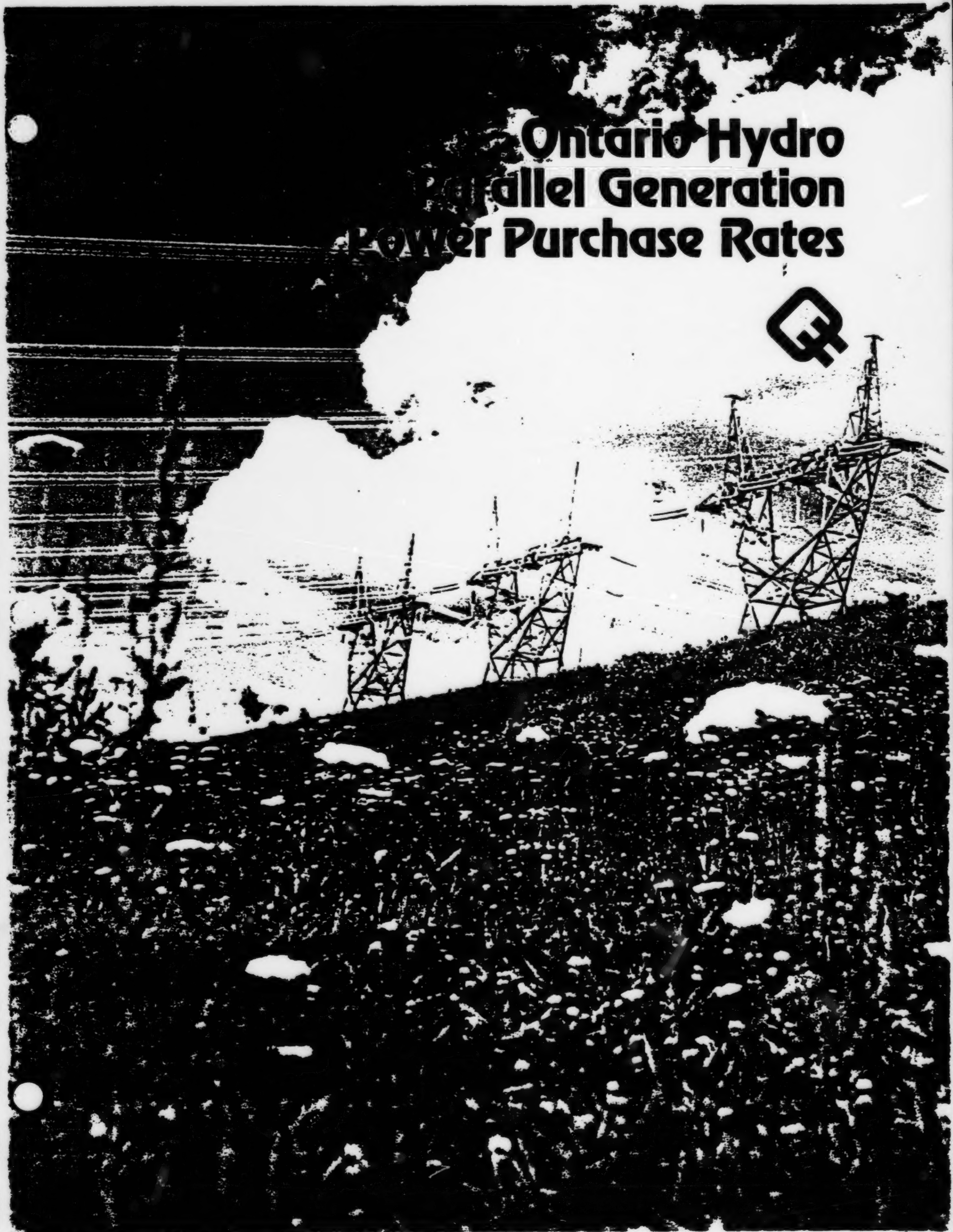
Residential Electricity Prices in Toronto
¢/kWh

	Low Case		Mid Case		High Case	
	1986$	Nominal $	1986$	Nominal $	1986$	Nominal $
1985	4.84	4.73	4.84	4.73	4.84	4.73
1986	4.87	4.87	4.87	4.87	4.87	4.87
1987	4.94	5.11	4.99	5.11	4.98	5.11
1988	5.10	5.41	5.10	5.38	5.07	5.36
1989	5.19	5.68	5.16	5.62	5.09	5.57
1990	5.29	5.99	5.21	5.90	5.12	5.82
1995	4.97	6.77	5.03	6.98	4.91	6.90
2000	5.08	8.41	4.84	8.28	4.40	7.75

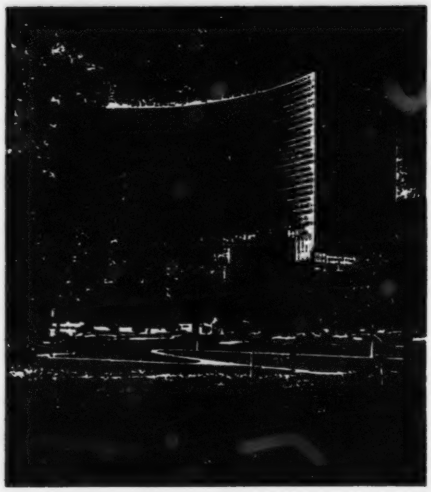
Figure 14
Residential Electricity Price
Toronto



Ontario Hydro
Parallel Generation
Power Purchase Rates



Ontario Hydro Parallel Generation Power Purchase Rates



In 1906 when Ontario Hydro was created by Provincial Statute as the Hydroelectric Power Commission of Ontario, there already existed over 150 power generation facilities in the province which were owned by private companies, municipalities and others. Although many of these power plants were eventually taken over by Ontario Hydro in fulfilling its mandate for a province-wide power system, there have continued to be power developments by "others" since that time. For many years, economies of scale have favoured large generation facilities, but more recently a revival of interest in parallel generation has resulted from new policies and programs of the Ontario Government, and Ontario Hydro's commitment to support private parallel generation by purchasing electricity from parallel generators at rates which reflect the long-term value to the power system.

Power Purchase Rates for Parallel Generators

INTRODUCTION

This pamphlet is intended to familiarize a prospective parallel generator (PG) with the rates and rate setting approaches used by Ontario Hydro for purchase of power. The pamphlet is one of three introductory pamphlets on parallel generation available from Ontario Hydro. The other two are "Purchase and Contract Conditions" and "Connection Procedure and Requirements". All three brochures are available from the Marketing Departments in the six Regional Offices of Ontario Hydro and should be referenced by those interested in developing a parallel generation project in Ontario for purposes of selling power to Ontario Hydro. As the project proceeds, meetings with Ontario Hydro will be required and more specific requirements may be identified depending on the Project.

POLICY ON RATES

Ontario Hydro actively encourages the development of parallel generation in Ontario and has a Corporate policy of being a willing buyer, subject to rate affordability and standard service conditions. With respect to purchase rates the following general policy applies:

- For projects delivering up to 5 Megawatts, rates are made available in pre-approved rate schedules. These rates are based on the following guidelines:
  - the rates may be higher than Ontario Hydro's avoided costs as an initial incentive to parallel generation, but with a ceiling equivalent to 85 percent of Ontario Hydro's accounting costs for power (the average wholesale cost of power).
  - at such time as rates based on the avoided costs to the power system as a whole exceed 85 percent of the system accounting costs, the rates will be based on the avoided costs (estimated cross-over to avoided cost based rates is early 1990's).
- For projects delivering over 5 Megawatts net, rates are determined on a project-by-project basis and shall not exceed the avoided cost specific to the project.
- Ontario Hydro may institute a competitive proposal process from time to time to help ensure projects in excess of 5 Megawatts are developed in an orderly and price competitive manner.

Currently, Ontario Hydro's rates for purchases from small parallel generation projects are based on accounting costs. Accounting costs are the costs incurred by Ontario Hydro to generate, transmit and distribute electricity to customers, using existing facilities.

Avoided costs reflect the expected costs of increased or decreased use of existing facilities or the expected cost of delaying or advancing additional resources (figure 1). For a more detailed explanation of avoided costs, refer to *Reference 1* available from Ontario Hydro. Purchase rates based on avoided costs are common practice in the U.S., where utility buyback rates are governed by the 1978 U.S. Public Utilities Regulatory Policies Act. Basing the purchase rates on Ontario Hydro's avoided costs is economically equitable to both buyer and seller. It also ensures optimum power system development at the lowest cost and maximum benefit to the economy of Ontario. For details on how Avoided Costs Based Purchase Rates are determined, refer to page 3 inset.

At the present time purchase rates for projects up to 5 MW that are based on system avoided costs would be lower than the rates as currently based on accounting costs. In 1988, an evaluation of avoided cost based rates for purchases yielded a rate that was approximately 90% of the rates based on accounting costs. This situation is expected to continue for a number of years until a cross-over occurs in the early 1990's (figure 2). During the period preceding the cross-over point Ontario Hydro intends to continue to set purchase rates for projects up to 5 Megawatts net according to the present accounting cost approach. These higher rates are considered appropriate to provide a stimulus to the initial development of parallel generation.

PURCHASE RATES

Rates for Contracted Purchases from Projects up to 5 MW Net

Ontario Hydro's purchase rates for contracted purchases of up to 5 MW include:

1. Standard energy rates determined by the generator's monthly capacity factor. (For monthly capacity factor definition please see page 5). Deliveries from generators at 65% monthly capacity factor or higher attract a higher energy rate level than deliveries below that capacity factor level.
2. Ten-year levelized energy rate offered to new projects using renewable resources.
3. Optional time-differentiated rates reflecting the relative value of electricity delivery during various time periods during the year.

The 1988 Standard Power Purchase Rates for projects up to 5[redacted] MW are as follows:

- The purchase rate for new projects with monthly capacity factors at or above 65% is 3.76¢/kWh.
- The ten-year fixed rate remains at 4.94¢/kWh for monthly capacity factors at or above 65%.
- For all projects with monthly capacity factors below 65% the rate remains at 2.54¢/kWh.
- For projects that are already in service, the 1987 standard purchase rate (3.60¢/kWh) has been indexed at actual Ontario CPI (4.7%), resulting in a power purchase rate of 3.77¢/kWh for monthly capacity factors at or above 65%.

Projects larger than 5000 kW will be required to seek a negotiated rate schedule based on the avoided costs specific to the project.

Standard Energy Rates

The standard energy rate for new generators who maintain a monthly capacity factor of 65% or higher is based on 85% of Ontario Hydro's accounting costs and is set at 3.76¢/kW.h for 1988.

Ontario Hydro's forecast of accounting cost for 1988 is $5,464 million and total energy sales are forecast to be 123,484 GW.h. The ratio of these two values is a unit rate of 4.42¢/kW.h. Eighty-five percent of 4.42¢ produces the above rate of 3.76¢/kW.h.

For generators that are already in-service, the 1987 standard purchase rate was 3.60¢/kW.h. Beginning in 1988, projects already in-service will have this base rate escalated each year at actual Ontario Consumer Price Index (CPI). Typically, CPI indexing is provided up to 10 years from the in-service date. Thereafter the base rate is renegotiated subject to the floor price provisions of the contract.

For generators that have a monthly capacity factor below 65%, the rate is set at 60% of Ontario Hydro's accounting costs for 1987. This level is maintained at the 1987 level in 1988 to advance the cross-over to avoided cost based rates. The rate in 1988 is 2.54¢/kW.h. This rate will continue to be reviewed annually by Ontario Hydro.

10-Year Levelized Energy Rate

For generators coming into service in 1988, the 10-year levelized energy rate is set at 4.94¢/kW.h. This rate option is available to new generators using renewable resources and maintaining a monthly capacity factor of 65% or higher. This rate was first introduced in 1987 and was designed to produce the same present value as the annual standard rates would produce over the same 10-year period. This rate is currently frozen at 4.94¢/kW.h as more recent forecasts project lower future rates than those originally used.

The eligibility criteria for the levelized rate are as follows:

- Projects must be based on renewable resources including: water power, solar, wind, wood-waste and municipal solid waste.
- Projects must provide new power generation capacity. This rate has a front-end loading feature to financially assist the development of new renewable resource based projects. Excluded are existing plants even if they change ownership, unless:
  (a) the plant has been out of service for at least five years; or

FIGURE 1
AVOIDED COSTS: 1988 - 2001
FOR SMALL CHANGES

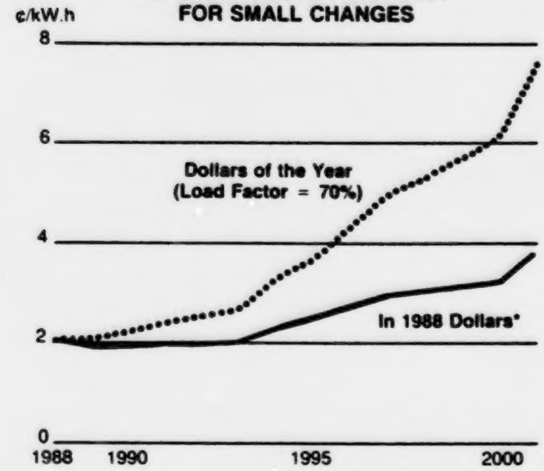
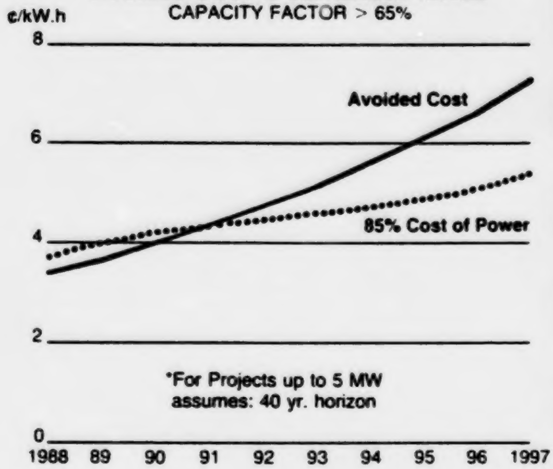


FIGURE 2
AVOIDED COST & COP BASED RATES
CAPACITY FACTOR > 65%



*For Projects up to 5 MW
assumes: 40 yr. horizon

AVOIDED COST BASED PURCHASE RATES

The evaluation of avoided capacity and energy costs was carried out for purchases from generators who maintain a monthly capacity factor of 65% or higher, as well as for generators who maintain a monthly capacity factor below 65%.

The method evaluates the smoothed avoided costs assuming no inflation over a 40-year horizon; the implicit assumption being that escalation will occur at the Consumer Price Index (CPI).

(a) Purchases From Generators Who Maintain Monthly Capacity Factor of 65% or Higher

Avoided Capacity Costs

The 40-year avoided capacity cost forecast is available in present value form in Table 1 of the document entitled "Incremental System Values of Power and Energy". (Reference 3)

The following steps are taken:

1. The real cost of capital is calculated by removing inflation from Ontario Hydro's nominal cost of capital over the 40-year horizon.
2. The present value for capacity, corresponding to the start year and over a horizon of 40 years, is smoothed over this period in real terms. This is accomplished using an annuity factor reflecting the real cost of capital over the 40 years.
3. To convert the avoided capacity cost (obtained in Step 2) from $/kW/year into ¢/kW.h, a representative system annual load factor of 68% (or 5,957 hours) is used. The conversion is accomplished by dividing the $/kW/year by the 5,957 hours and multiplying by 100 to convert it to ¢/kW.h.

The result is the value of the smoothed avoided capacity component in real terms.

Avoided Energy Costs

The avoided energy cost forecast is available in nominal values, ie, dollars of the year as shown in Table 2 of the document mentioned above. To calculate the smoothed value of that energy in real terms over the same 40-year horizon employed for the capacity calculation, the following steps are taken:

1. The real cost of capital is calculated from the nominal cost of capital using CPI for the start year.
2. The nominal avoided energy cost is expressed in real terms by deflating the values to the start year using CPI.
3. The present value of the real avoided energy cost (Step 2) is calculated using the real cost of capital (Step 1).
4. All the present values over the 40-year horizon are summed.
5. A smoothed value in real terms in cents per kilowatt hour is obtained by amortizing the value obtained in Step 4 over the 40-year horizon using an annuity factor reflecting the real cost of capital.

The result is the value of the smoothed avoided energy component in real terms.

Addition of the two avoided components, capacity and energy, results in a value based on a single set of forecasts.

To ensure stability of the results, the most recent five consecutive forecasts are used and a simple average of these five forecasts is then calculated. For 1988, this evaluation would produce a result of 3.40¢/kW.h.

(b) Purchases From Generators Who Maintain Monthly Capacity Factor of Less Than 65%

The procedure is similar to the one described in section (a) above, except that the purchase rate does not include a capacity component and the time horizon used is 10 years instead of 40 years. This 10-year horizon provides more stability than a calculation based on one year only.

For 1988, this evaluation would produce a result of 2.25¢/kW.h.

(c) Fixed 10-Year Energy Rate

This rate was developed as an incentive rate for new capacity generation from renewable resources which maintains a monthly capacity factor of 65% or higher.

The calculation was undertaken in April 1986, in response to a request from the Minister of Energy.

Application of the same methodology with subsequent avoided capacity and energy cost forecasts yielded lower 10-year fixed rates. To encourage electricity generation from renewable resources, Ontario Hydro decided to maintain the originally proposed 10-year fixed rate of 4.94¢/kW.h.

[illegible]
Printed in Canada · March 88

(b) the plant has been extensively redeveloped or rehabilitated with at least a 25% increase in power capacity and annual energy production.

- Projects will be reviewed to assess Hydro's financial exposure during the fixed rate term. Projects assessed as "risky" will be required to post financial surety equivalent to the advance payments.

Optional Time-Differentiated Rates

Optional time-differentiated rates are offered to generators with capacities of 250 kW or greater. Currently the rate differentials are based on the pre-1985 time-differentiated accounting cost studies. This is consistent with setting the rates as a percentage of accounting costs. The level of the time-of-use rates for capacity and energy reflect an equivalent level to the 3.76¢/kW.h applicable for generators who maintain a monthly capacity factor of 65% or higher.

The energy component of the time-of-use rates reflects an equivalent level to the 2.54¢/kW.h applicable for generators who maintain a monthly capacity factor of less than 65%.

The rates are:

Capacity Rates

Winter	$7.96 per kW per month
Summer	$3.98 per kW per month

Energy Rates

Winter Peak	3.19¢ per kW.h
Winter Off-Peak	2.54¢ per kW.h
Summer Peak	2.79¢ per kW.h
Summer Off-Peak	1.74¢ per kW.h

The periods are defined as follows:

Winter:	October through March
Summer:	April through September
Peak:	7 am to 11 pm weekdays
Off-Peak:	11 pm to 7 am weekdays, plus all weekends and public holidays

Rates for Contracted Purchases from Projects Delivering Over 5 MW Net

As outlined on page 1, the rates for projects over 5 MW net will be determined on a project by project basis and shall not exceed the avoided cost specific to the project.

Upon receipt of initial project information as outlined in the pamphlet "Parallel Generation - Purchase and Contract Conditions", Ontario Hydro will estimate the avoided cost of a project and make a firm commitment on maximum price, normally within 60 days of receiving the initial project information. The actual contract price will then be based on the maximum price adjusted for reliability as predicted by the parallel generator. An initial adjusted pricing proposal may be submitted by the project proponent, after being advised by Ontario Hydro of the maximum price. If the adjusted price is accepted by Ontario Hydro it becomes the contract price.

Reference 2 outlines in detail the procedure followed to set rates for projects delivering over 5 MW net. It should be noted however, that Ontario Hydro reserves the right from time to time to waive the procedure in favour of a competitive proposal process for new contracts.

The avoided cost of the project will generally depend on six factors:

- the in-service date of the project.
- the term of the power purchase agreement (normally expected project life).
- the total amount of energy delivered over the term of the power purchase contract.
- the coincidence of the power and energy deliveries with the peak demand periods of the power system.
- the reliability of the plant to deliver the energy and power as predicted.
- integration aspects with the existing and future power system, such as compatibility of the hydraulic operation with other plants downstream, possible credits for any deferment of planned facilities on the local transmission system, or reduced losses on local lines. Integration aspects can have an increasing or decreasing effect on avoided costs.

Rates for Non-Contract (At-Will) Purchases

Ontario Hydro's rates for purchases from direct customers delivering energy on an occasional basis only are set at 3.76¢/kW.h multiplied by the monthly capacity factor, based on the peak delivery for the month with a floor price equal to the energy rate applicable to direct customer purchases from Ontario Hydro. For 1988, the floor price is 2.23¢/kW.h.

FLOOR PRICE

To improve the "bankability" of parallel generation projects, Ontario Hydro will commit itself to defining purchase rate escalations for a period normally up to 10 years as noted on page 2. For projects based on non-renewable fuels, the rate defined period may be extended to the term of the fuel contract.

Ontario Hydro will also commit itself to defining minimum purchase rates or "floor" rates for the full contracted term. These "floor" rates are defined as follows:

- the floor rates for the initial rate defined period (10 years) will be the rates in the in-service year;
- for the remaining contract term the floor rates shall be the higher of the rates in the in-service year or the rates in the last year of the initial rate defined period (year 10).

CAPACITY FACTOR

For projects up to 5 MW capacity factor for the month is defined as the ratio between 1) the total kilowatt hours delivered in the month and 2) the product of the peak kilowatts delivered and the number of hours in the month.

As previously noted deliveries from generators at 65% monthly capacity factor or higher attract a higher energy rate level than deliveries below that capacity factor level. As a result, it is to the advantage of the generator to operate at a consistently high generation level.

In some cases, small hydro run-of-the-river projects have difficulty meeting the 65% capacity factor threshold due to significant variations of water flow over a short period of time. As a result, some small hydro generators would rather spill water than generate during a high river flow period if it assists them in qualifying for the higher purchase rates.

Ontario Hydro has acknowledged this potential waste of hydraulic resources and at the present time can offer small hydraulic generators alternatives to the 65% capacity factor threshold as outlined in the "Additional Rates" inset below.

ADDITIONAL RATES FOR PURCHASE OF PARALLEL GENERATION IN ONTARIO

The rates specified below are applicable only to small hydro projects up to 5,000 kW of net capacity selling power to Hydro under contract.

Time-Differentiated Energy Rate Alternative

Winter Peak	5.42 cents per kWh
Winter Off-Peak	2.51 cents per kWh
Summer Peak	4.95 cents per kWh
Summer Off-Peak	1.70 cents per kWh

Time-of-Use

Winter	October through March
Summer	April through September
Peak	7 am to 11 pm weekdays
Off-Peak	11 pm to 7 am weekdays, plus all weekends and public holidays

Sliding Scale Alternative

a) Standard Purchase Rates

For capacity factors of 75% or greater - 3.76 cents per kWh

For capacity factor between 50 and 75 percent, the following formula applies:

Payment = 2.54 X E + 1.22/25 X (ACF% − 50%) X E

Where

- 2.54¢/kWh is the rate applicable to capacity factors below 50%
- E kWh is the energy delivered in the month
- 1.22¢/kWh is the difference between the rate above 75% capacity factor and the rate below 50% capacity factor (1.22 = 3.76 − 2.54)
- 25% is the value of the capacity factor interval considered (50% to 75%)
- ACF% is the actual monthly capacity factor or 75% whichever is less
- 50% is the initial value of the capacity factor interval considered

For capacity factors below 50% − 2.54 cents per kWh

The monthly capacity factor is based on the rated kilowatt capacity of the generator or the peak measured in kilowatts delivery in the demand interval of the month.

b) Fixed 10-Year Purchase Rate for New Renewable Resources Based Projects

For capacity factors of 65% or greater - 4.94 cents per kW.h

For capacity factors between 50 and 65%, the above formula applies.

References

1. "Avoided Costs: Ontario Hydro's Experience," by Amir Shalaby, Ontario Hydro System Planning Division, IEEE Power Eng. Soc., Winter Meeting, February 1988.
2. "Power Purchase Pricing Procedure for Projects Proposing to Sell over 5 MWe", Ontario Hydro Pamphlet, March 1988.
3. "Incremental System Values of Power and Energy", System Planning Division, Ontario Hydro.

All contact with Ontario Hydro should be through the Manager-Marketing in the appropriate Region.

Central
5760 Yonge Street
WILLOWDALE, Ontario
M2M 3T7
(416) 222-2571

Eastern
420 Dundas Street East
BELLEVILLE, Ontario
K8N 5C3
(613) 966-8622

Georgian Bay
93 Bell Farm Road
BARRIE, Ontario
L4M 1H1
(705) 728-5521

Northeastern
590 Graham Drive
NORTH BAY, Ontario
P1B 8L4
(705) 472-8000

Northwestern
34 Cumberland Street North
THUNDER BAY, Ontario
P7A 4L5
(807) 343-3411

Western
1075 Wellington Road
LONDON, Ontario
N6E 1M1
(519) 681-1390

APPENDIX D
QUESTIONNAIRES

COGENERATION ASSESSMENT QUESTIONNAIRE

The Proctor & Redfern Group have been retained by the Ontario Ministry of Energy to evaluate the cogeneration opportunities in Ontario's Commercial Sector.

Completion of this form with the best available information and its return to us will enable a representative of our company to visit your establishment to make an assessment of the financial viability of a cogeneration system.

Site to be Surveyed

Company Name ______________________________

Address ______________________ City ______________

Prov. ______________________ Postal Code __________

Company Contact

Name ______________________ Title ______________

Address ______________________ Telephone (   )__________

Nature of Business

____

____

GENERAL INFORMATION

1. Cost

   The site visit and ensuing cogeneration feasibility analysis will be carried out without any cost or obligation to the Building Owner.

2. Confidentially

   All of the information contained in this questionnaire and the energy analysis remains strictly confidential.

   A copy of the results of this assessment will be made available to the Building Owner at the end of this project.

7

3. Information

The general information requested in this form is required for a preliminary evaluation. If the information is not available or is unknown, please indicate by writing in the appropriate space.

Specific utility cost and contract rate structure information may be required for development of the incremental cost rates and energy consumption profiles. The owner may be required to provide authorization to each energy supplier allowing for release of this information.

4. Site Assistance

The Owner shall provide the site analyst with a tour of the applicable facility areas and then be reasonably accessible to answer questions and provide additional information.

5. Owner's Acknowledgement

Signature of person authorizing the cogeneration assessment.

Name ____________________ Title ________________ Date __________

PURCHASED ENERGY

To provide details of all energy costs and major contracts, please complete the information below and provide photocopies of all utility billings for the past 13 consecutive months. Also provide a photocopy of the most recent utility contracts, if available.

Electricity

Name of Supplier ___________________________ Telephone (   ) __________

Natural Gas

Name of Supplier ___________________________ Telephone (   ) __________

Type of Contract _______________ Firm _______________ Interruptable ______

Other Energy Forms (Provide type, and source details)

____

____

____

Normal schedule of operations.

Hours/day ____ Hours/week ____ Weeks/year ____ Shutdown period ____ wks

Seasonal variations ____________________

MAIN UTILITIES

Number of Boilers ________ Steam ________ Hot Water ________

Total capacity ________ BTU/hr ________ lbs/hr

Steam press _____psi Steam temp. ____deg F. Hot Water temp. ____deg F

Primary fuel ________ Secondary fuel ________

Use: ________% Process ________% Heating

Electrical

Number of transformer stations ______ Total connected kVA ________

Single line distribution drawing ________attached ________ to follow

Absorption Refrigeration Systems

Number ________ Total Capacity ________ tons

Heating Systems

Steam ________ Hot Water ________ Others ________

Previous Cogeneration Assessment _____ Yes _____ No ________ Year

Can you provide comments which would be pertinent to a cogeneration assessment.

Return to: The Proctor & Redfern Group
45 Green Belt Drive
Don Mills, Ontario M3C 3K3

Attention: Michael Martin

Telephone (416) 445-3600
Fax (416) 445-5276

COGENERATION ASSESSMENT

SITE SURVEY

Site Data

1. **NAME:** ______________________________
LOCATION: ______________________________
____

2. **GENERAL SITE/PROCESS DESCRIPTIONS:**
____
____
____

3. **OCCUPANCY:**

Weekday ________ Hours/Day
________ Days/Week

Saturday ________ Hours/Day
Sunday ________ Hours/Day

SCHEDULED SHUTDOWNS: (Process Load Profile Information)
____
____

4. **HVAC SYSTEM TYPE:**

________ Electric Baseboard
________ Gas/Electric Unit Heaters
________ Central Plant Heating & Cooling Systems
________ 2-Pipe Fan-Coil
________ Hot Water Radiant
________ Incremental Heat Pumps
________ Air Handling Systems w/Heating & Cooling Coils

________ Electric Radiant Panels
________ Incremental Through the Wall Electric
________ Air Handling Systems w/Hot Water Heating
________ Hot Water Baseboard
________ Steam Unit Heaters
________ Hot Water Unit Heaters

AIR CONDITIONING CHILLER TYPE

________ Heat Driven (Absorption or Steam)

________ Electrically Driven

5. **ELECTRIC DATA:**

Electric Utility Providing Site Power ______________________________

Existing Rate Designation ______________________________

Existing Service:

_______ volts _______ kW _______ amps

_______ volts _______ kW _______ amps

FIRST MONTH _______ LAST MONTH _______

Month	Billing Demand	Electric Use (kWh)	Cost ($)

MAXIMUM BILLING DEMAND ________ kW

TOTAL COST ________ $/Year

TOTAL USE ________ kWh/Year

AVERAGE COST ________ $/kWh

Notes:

6. GAS DATA

Existing Service:

On-Site		In-Street	
CAPACITY	________	CAPACITY	________
PRESSURE	________	PRESSURE	________
RATE	________		
FIRST MONTH	________*	LAST MONTH	________

Month	Billing Demand (if applicable)	Consumption (therms)	Cost ($)

MAXIMUM BILLING DEMAND ________ therms (if applicable)

TOTAL COST ________ $/Year

CONSUMPTION ________ therms/Year

AVERAGE COST ________ $/therms

Notes:

Do not include gas used for processes such as cooking or incineration for which recovered heat cannot be used.

*The first month must be the same month as was used for the first month of electrical data.

7. SUPPLEMENTARY HEATING FUEL DATA

Fuel Type ________ Supplier ________
First Month ________* Last Month ________

Month	costs ($)	quantity ( )	________ ( )	________ ( )	________ ( )
TOTAL					

Total Fuel Cost ____________ $/year

Total Fuel Consumption ____________ (________/year)

Average Cost ____________ ($/__________)

Projected Fuel Cost ____________ ($/__________)

Fuel Heat Content ____________ (therms/________)

Equivalent Gas Requirement ____________ therms

If metered data are available compute conversion efficiency:

____

____

Notes:

*The first month must be the same month as was used for the first month of electrical data.

8. SPECIAL THERMAL REQUIREMENTS

Describe any critical thermal energy loads which must be maintained.

List any high temperature water requirements. (above 250°F)

List any high pressure steam requirements. (above 15 psig)

9. SPECIAL ELECTRICAL REQUIREMENTS

Describe any electrical loads with special voltage requirements.

Frequency control requirements.

Harmonic content requirements.

List all motors above 30 HP (size, use)

Describe the requirements for emergency service or baseloads requirements (use, capacity).

____

____

____

____

Notes:

UTILITY DATA

10. CONVENTIONAL ELECTRIC RATE SCHEDULE

Designation ______________________________

Rate Schedule ______________________________

____

____

____

____

Historic Fuel Adjustment Charge ______________

Projected Fuel Adjustment Charge ______________

Projected Cost Purchased Power ______________

11. COGENERATION RATE SCHEDULE

Standby Power ______________

____

____

____

Supplemental Power ______________

____

____

____

12. BUY BACK RATE

Electric Utility Name ______________

Avoided Cost Rate ______________

13. PROJECTED GAS HEATING RATE ________ $/therm

14. PROJECTED GAS COGENERATION RATE ________ $/therm

15. PROJECTED ENERGY COST

Oil ________ $/Gal

Steam ________ $/Thousand Pounds

________ $/______________

16. PROJECT CONVENTIONAL UTILITY COST

Electric

a. Historic Annual Electric Cost (Question 5) ________ $/yr.

b. Electrical Consumption (Question 5) ________ kWh

c. Projected Average Power Rate (Question 10) ________ $/kWh

d. Projected Electric Power Costs (b x c) ________ $/yr.

Gas

e. Historic Annual Electric Cost (Question 6) ________ $/yr.

f. Electrical Consumption (Question 6) ________ therm/yr.

g. Projected Heating Gas Rate (Question 13) ________ $/therm

h. Projected Gas Cost Costs (f x g) ________ $/yr.

Other Fuels

Fuel Type ________________________________

i. Historic Fuel Costs (Question 7) ________ $/yr.

j. Annual Consumption (Question 7) ________/yr.

k. Projected Unit Cost (Question 15) ________ $/___

l. Projected Fuel Costs (j x k) ________ $/yr.

Annual Cost Summary

m. Historic Cost (a+e+i) ________ $/yr.

n. Projected Cost (d+h+e) ________ $/yr.

o. Utility Cost Change (n-m) ________ $/yr.

p. Projected Increase (100 x o + m) ________ %